Table 8-2 Group 1 Cluster NRIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
BETHEL - BROKEN BOW 138KV CKT 1	98	104.62	P23:345:AEPW:PITTSBURG CB 3429A NBTB	Rebuild finished per 2015 ITP10, Bethel - Broken Bow 138kV
CIMARRON (CIMARON1) 345/138/13.8KV TRANSFORMER CKT 1	382	149.12	P42:345:OKGE:SB_CION7382	Build a 3rd xfmr at Cimarron 345kV
CIMARRON (CIMARON2) 345/138/13.8KV TRANSFORMER CKT 1	382	122.47	CIMARRON (CIMARON1) 345/138/13.8KV TRANSFORMER CKT 1	
DOVER SW - HENESSEY 138KV CKT 1	191	102.48	CRESENT - TWIN LAKES 138KV CKT 1	Terminal equipment
TUPELO - TUPELO TAP 138KV CKT 1	143	103.8	P23:345:AEPW:PITTSBURG CB 3429A NBTB	Rebuild Tupelo - Tupelo Tap 138kV (NRIS)

CLUSTER GROUP 2 (HITCHLAND AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

Several ERIS thermal constraints were observed for system-intact, single contingency (N-1), and multi-contingency (P1, P2, etc.) conditions. The table below summarizes constraints and associated mitigations.

Table 8-3 Group 2 Cluster ERIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
Hansford County Switch Station - SPEARMAN INTERCHANGE 115KV CKT 1	158.95	100.38	System Intact	Upgrade terminal equipment
MAJESTIC WIND - MARTIN SUB 115KV CKT 1	163.13	99.6	System Intact	Interconnection Customer facility. Interconnection Customer would need to review for mitigation.
MARTIN SUB - PANTEX NORTH SUB 115KV CKT 1	159.34	106.31	HUTCHINSON COUNTY INTERCHANGE S. - MARTIN SUB 115KV CKT 1	Previously assigned per SPP NTC-200444 to replace terminal equipment.
HIGHLAND PARK TAP - PANTEX SOUTH SUB 115KV CKT 1	153.97	106.1	HUTCHINSON COUNTY INTERCHANGE S. - MARTIN SUB 115KV CKT 1	
CAPROCK REC-PEMBROOK () 115/69/13.2KV TRANSFORMER CKT 1	48.6	184.93	CAPROCK REC-PEMBROOK - POWELL CNR 3115.00 115KV CKT 1	Affected System Facilities for TCEC. TCEC could require a review and mitigation
ELKHART TAP - EVA REGULATOR 69KV CKT 1	20	142.05	CAPROCK REC-PEMBROOK - POWELL CNR 3115.00 115KV CKT 1	

CLUSTER GROUP 3 (SPEARVILLE AREA)

No additional generation was studied for this group.

CLUSTER GROUP 4 (NORTHWEST KANSAS AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C

Several ERIS thermal constraints were observed for single contingency (N-1), and multi-contingency (P1, P2, etc.) conditions. The table below summarizes constraints and associated mitigations. The table below summarizes constraints and associated mitigations.

Table 8-4 Group 4 Cluster ERIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
HOYT - JEFFREY ENERGY CENTER 345KV CKT 1	1076	103.44	P23:345:WERE:RENO_345-140::G16111TAP	Advance Geary 345/115kV Substation and Geary-Chapman 115kV Ckt1 and rebuild Hoyt – Jeffrey Energy Center
SUMMIT (SUMM TX-1) 345/230/14.4KV TRANSFORMER CKT 1	598	103.29	G16-111-TAP 345.00 - RENO COUNTY 345KV CKT 1	
RENO COUNTY (RENO TX-1) 345/115/14.4KV TRANSFORMER CKT 1	308	124.18	P23:345:WERE:RENO_345-160::	Add 3rd 345/115/14.4kV Transformer
RENO COUNTY (RENO TX-2) 345/115/14.4KV TRANSFORMER CKT 1	308	124.42	P23:345:WERE:RENO_345-150::	

In addition to the ERIS constraint mitigations, several NRIS thermal and voltage constraints were observed for single contingency (N-1), and multi-contingency (P1, P2, etc.) conditions. The table below summarizes constraints and associated mitigations assignable to those requests that elect NRIS.

Table 8-5 Group 4 Cluster NRIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
RENO COUNTY (RENO TX-1) 345/115/14.4KV TRANSFORMER CKT 1	308	121.34	P23:345:WERE:RENO_345-160::	Add 3rd 345/115/14.4kV Transformer
RENO COUNTY (RENO TX-2) 345/115/14.4KV TRANSFORMER CKT 1	308	122.17	P23:345:WERE:RENO_345-150::	
SUMMIT (SUMM TX-1) 345/230/14.4KV TRANSFORMER CKT 1	598	102.76	G16-111-TAP 345.00 - RENO COUNTY 345KV CKT 1	Advance Geary 345/115kV Substation and Geary-Chapman 115kV Ckt1
BUCKEYE_230 230.00 (BUCK_E_MPT) 230/34.5/13.8KV TRANSFORMER CKT 2	110	108.4	System Intact	IC Facility – Not for Current Study Mitigation

CLUSTER GROUP 6 (SOUTH TEXAS PANHANDLE/NEW MEXICO AREA)

The requested POI for GEN-2016-077 is not viable, additional analysis will be required to identify if additional mitigation is required with a viable POI on the requested circuit. The interconnection cost estimate is for a valid POI on the requested circuit.

New requests for this study group as well as prior-queued requests are listed in Appendix C

ERIS thermal constraints were observed for single contingency (N-1), and multi-contingency (P1, P2, etc.) conditions. The table below summarizes constraints and associated mitigations.

Below is a list of the upgrades assigned, and the corresponding scenarios in which these upgrades were assigned. Scenario numbers are denoted as "S#".

Table 8-6 Group 6 Cluster Upgrade Scenarios

Scenario	Incremental Mitigation
0	Add temporary study SVCs at various locations to achieve a solved dispatch
2	Add Crawfish Draw - Seminole 765kV Ckt 1
	Remove temporary SVCs at various locations
3	Add Crawfish Draw - Seminole 765kV Ckt 2
4	Add Crossroads - Crawfish Draw 765kV Ckt 1
5	Add 3rd Tolk 345/230kV transformer
	Add 2nd Crawfish Draw 345/230kV transformer
6	Mitigate Crossroads - Tolk 345kV CKT 1 clearance and terminal ratings issues
	Reconductor Pittsburg - Seminole 345kV CKT 1
	Reconductor Cochran - Lost Draw 115kV CKT 1
	Add +600MVAR SVC at Crawfish Draw 765kV substation
	Add Midpoint 765kV substation tying both Crawfish Draw - Seminole 765kV circuits together
	Remove in-line reactors on Crawfish Draw - Crossroads 765kV CKT 1
	Remove in-line reactors on Crawfish Draw - Midpoint - Seminole 765kV CKT 1 &2
	Add 700MVAR switched shunt reactors at Crawfish Draw 765kV substation
	Add 1,600MVAR switched shunt reactors at Midpoint 765kV substation
	Add 300MVAR switched shunt reactors at Seminole 765kV substation
7	Replace terminal equipment on Elk City 230/138/13.8KV Transformer CKT 1

Several steady state voltage constraints for mitigation were identified with the inclusion of thermal and stability constraint mitigations. The results identified a need to include significant switchable reactive compensation for the 765kV transmission line charging current that will be refined in the facility study. SPP determined the 765 kV Network Upgrade cost estimates using conceptual amounts which require a facility study to substantiate.

Table 8-7 Group 6 Cluster Non-Convergence ERIS Constraints

Monitored Elements	Mitigation
System Intact	Scenario 0 Model was solved using temporary study SVC's in various locations throughout the South Texas panhandle/New Mexico area; see appendix G-T for various non-converging scenario 0 results.
CRAWFISH765 765.00 - SEMINOLE765 765.00 765KV CKT 1	In addition to higher queued assigned upgrades the following new upgrades are required for group 6 potential voltage collapse:
BORDER 7345.00 - G16-120-TAP 345.00 345KV CKT 1	

BORDER 7345.00 - WOODWARD DISTRICT EHV 345KV CKT 1	1. Add Crawfish Draw - Seminole 765KV CKT 1 2. Add Crawfish Draw - Seminole 765KV CKT 2 3. Add Crossroads - Crawfish Draw 765kv CKT 1
CRAWFISH_DR 345.00 - OKLAUNION 345KV CKT 1	
ELM CREEK - MRWYP16 230KV CKT 1	
GEN520947 1-HUGO1	
Hitchland Interchange - POTTER COUNTY INTERCHANGE 345KV CKT 1	
HUGO - VALLIANT 345KV CKT 1	
POTTER COUNTY INTERCHANGE - TOLK STATION 345KV CKT 1	
TUCO INTERCHANGE - YOAKUM_345 345.00 345KV CKT 1	
CHAVES COUNTY INTERCHANGE - SAN JUAN MESA TAP 230KV CKT 1	
CROSSROADS 7345.00 - TOLK STATION 345KV CKT 1	
G16-063-TAP 345.00 - SUNNYSIDE 345KV CKT 1	
LAWTON EASTSIDE - TERRYRD7 345.00 345KV CKT 1	
LYDIA - WELSH 345KV CKT 1	
NORTHWEST TEXARKANA - VALLIANT 345KV CKT 1	
OASIS INTERCHANGE - SAN JUAN MESA TAP 230KV CKT 1	
PITTSBURG - VALLIANT 345KV CKT 1	
PITTSBURG - SEMINOLE 345KV CKT 1	

Table 8-8 Group 6 Cluster Non-Convergence NRIS Constraints

All non-converged constraints are mitigated by ERIS assigned upgrades.

Table 8-9: Group 6 Cluster ERIS Thermal Constraints

Monitored Elements	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
CASTRO COUNTY INTERCHANGE - DEAF SMITH REC-#21 115KV CKT 1	159.0	117.8086	System Intact	Add Crawfish Draw – Seminole 765kV CKT 1 and CKT 2
CHISHOLM6 230.00 - ELK CITY 230KV 230KV CKT 1	353.0	134.728	System Intact	
CIMARRON - MINCO 345KV CKT 1	956.0	118.654	SUNNYSIDE - TERRYRD7 345.00 345KV CKT 1	
CRAWFISH_DR 345.00 - OKLAUNION 345KV CKT 1	1022.0	116.1433	System Intact	
GRAPEVINE INTERCHANGE - NICHOLS STATION 230KV CKT 1	318.69	100.4122	System Intact	
Hitchland Interchange - POTTER COUNTY INTERCHANGE 345KV CKT 1	956.09	121.8916	System Intact	
LAWTON EASTSIDE - OKLAUNION 345KV CKT 1	1011.0	110.0991	System Intact	
MOORE COUNTY INTERCHANGE - POTTER COUNTY INTERCHANGE 230KV CKT 1	318.69	111.655	System Intact	
NEWHART 230 - POTTER COUNTY INTERCHANGE 230KV CKT 1	375.26	104.4846	System Intact	

Monitored Elements	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
ALLRED TAP - SHELL C3 TAP 115KV CKT 1	232.64	99.8	INK_BASIN 6230.00 - YOAKUM COUNTY INTERCHANGE 230KV CKT 1	Add Crossroads - Crawfish Draw 765kv CKT 1
AMOCO SWITCHING STATION - SUNDOWN INTERCHANGE 230KV CKT 1	318.69	102.2611	NEEDMORE 230.00 - TOLK STATION WEST 230KV CKT 1	
AMOCO SWITCHING STATION - YOAKUM COUNTY INTERCHANGE 230KV CKT 1	414.3	105.3258	NEEDMORE 230.00 - TOLK STATION WEST 230KV CKT 1	
ANDREWS 3115.00 - National Enrichment Plant Sub 115KV CKT 1	525.0	111.4875	HOBBS (UPDATE DATA) 345/230/13.2KV TRANSFORMER CKT 1	
CRAWFISH_DR 345.00 - TUCO INTERCHANGE 345KV CKT 1	1793.0	100.2604	CRAWFISH_DR 345.00 - TUCO INTERCHANGE 345KV CKT 2	
CROSSROADS 7345.00 - TOLK STATION 345KV CKT 1	717.06	134.4355	HOBBS - YOAKUM_345 345.00 345KV CKT 1	
CUNNIGHM_S 6230.00 - HOBBS INTERCHANGE 230KV CKT 1	502	120.2338	'G15079_T 230.00 - YOAKUM COUNTY INTERCHANGE 230KV CKT 1'	
DENVER CITY INTERCHANGE S. - SHELL C2 SUB 115KV CKT 1	159.34	137.035	INK_BASIN 6230.00 - YOAKUM COUNTY INTERCHANGE 230KV CKT 1	
ELK CITY 230KV (ELKCTY-6) 230/138/13.8KV TRANSFORMER CKT 1	287.0	164.7449	System Intact	
G15079_T 230.00 - YOAKUM COUNTY INTERCHANGE 230KV CKT 1	377.65	161.0263	CUNNIGHM_S 6230.00 - CUNNINGHAM STATION 230KV CKT *1	
INK_BASIN 6230.00 - YOAKUM COUNTY INTERCHANGE 230KV CKT 1	377.65	137.3157	HOBBS - YOAKUM_345 345.00 345KV CKT 1	
LYNTEGAR REC-CLAUENE - TERRY COUNTY INTERCHANGE 115KV CKT 1	79.67	103.2663	COCHRAN INTERCHANGE - NEWTAP3 115.00 115KV CKT 1	
SUNDOWN INTERCHANGE - WOLFFORTH INTERCHANGE 230KV CKT 1	318.69	105.5874	CRAWFISH_DR 345.00 - TOLK STATION 345KV CKT 1	
TUCO INTERCHANGE (GE M1022338) 345/230/13.2KV TRANSFORMER CKT 1	644.0	99.9	CRAWFISH_DR 345.00 - TOLK STATION 345KV CKT 1	
TOLK STATION (TOLK2) 345/230/13.2KV TRANSFORMER CKT 1	560	146.6726	"P44:69:SPS:ARTESIA _4740"	Add Tolk XFMR 345/230/13.2kV Transformer CKT 3
CRAWFISH_DR 345.00 (CRAWFISHXFMR) 345/230/13.2KV TRANSFORMER CKT 1	560.0	113.1884	TUCO INTERCHANGE (SIEM 8743066) 345/230/13.2KV TRANSFORMER CKT 2	Add Crawfish Draw 345/230kv Transformer CKT 2

Monitored Elements	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
COCHRAN INTERCHANGE - NEWTAP3 115.00 115KV CKT 1	120.9	127.75	System Intact	Reconductor Cochran - Lost Draw 115kV CKT 1
CROSSROADS 7345.00 - TOLK STATION 345KV CKT 1	717.06	134.43	HOBBS - YOAKUM_345 345.00 345KV CKT 1	Crossroads - Tolk 345kV CKT 1 terminal equipment
PITTSBURG - SEMINOLE 345KV CKT 1	717	110.59	System Intact	Reconductor Pittsburg-Seminole 345 kV Ckt 1
ELK CITY 230KV (ELKCTY-6) 230/138/13.8KV TRANSFORMER CKT 1	272	100.72	System Intact	Replace transformer terminal equipment
'National Enrichment Plant Sub - TARGA 3115.00 115KV CKT 1'	139.03	102.1341	'CUNNIGHM_S 6230.00 - CUNNINGHAM STATION 230KV CKT *1'	Rebuild 3 miles of 115 kV from Cardinal – Targa per NTC 200360

Table 8-10: Group 6 Cluster NRIS Thermal Constraints

All constraints are mitigated by ERIS assigned upgrades.

The table below summarizes constraints and associated mitigations assignable to incremental ERIS steady state voltage. The steady state voltage constraints for mitigation are identified incremental to the thermal constraint mitigations.

Table 8-11 Group 6 Cluster ERIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
'BORDER 7345.00 345KV'	1.057966	0.9	1.05	'CHISHOLM7 345.00 - GRAPEVINE 345.00 345KV CKT 1'	Border Switched Shunt Adjustment
'BORDER 7345.00 345KV'	1.058209	0.9	1.05	'GRAPEVINE 345.00 - POTTER COUNTY INTERCHANGE 345KV CKT 1'	
'BORDER 7345.00 345KV'	1.058851	0.9	1.05	'BORDER 7345.00 - WOODWARD DISTRICT EHV 345KV CKT 1'	
'BORDER 7345.00 345KV'	1.063357	0.9	1.05	'BORDER 7345.00 - G16-120-TAP 345.00 345KV CKT 1'	
'COLE 2 69.000 69KV'	1.053588	0.9	1.05	'MINGO - RED WILLOW 345KV CKT 1'	Cole transformer tap adjustment

The table below summarizes constraints and associated mitigations assignable to incremental NRIS steady state voltage. The steady state voltage constraints for mitigation are identified incremental to the thermal constraint mitigations.

Table 8-12 Group 6 Cluster NRIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
'ANDREWS 6230.00 230KV'	1.091213	0.9	1.05	'HOBBS (UPDATE DATA) 345/230/13.2KV TRANSFORMER CKT 1'	Andrews transformer tap adjustment
'CHAVES COUNTY INTERCHANGE 230KV'	1.073083	0.9	1.05	'OASIS INTERCHANGE - SAN JUAN MESA TAP 230KV CKT 1'	
'CHAVES COUNTY INTERCHANGE 230KV'	1.096556	0.9	1.05	'CHAVES COUNTY INTERCHANGE - EDDY_NORTH 6230.00 230KV CKT 1'	
'GEN-2016-062230.00 230KV'	1.091213	0.9	1.05	'HOBBS (UPDATE DATA) 345/230/13.2KV TRANSFORMER CKT 1'	
'CHAVES COUNTY INTERCHANGE 230KV'	1.073083	0.9	1.05	'OASIS INTERCHANGE - SAN JUAN MESA TAP 230KV CKT 1'	San Juan Mesa Windfarm Switched Shunt Adjustment
'CHAVES COUNTY INTERCHANGE 230KV'	1.096556	0.9	1.05	'CHAVES COUNTY INTERCHANGE - EDDY_NORTH 6230.00 230KV CKT 1'	
'OASIS INTERCHANGE 230KV'	1.058381	0.9	1.05	'CHAVES COUNTY INTERCHANGE - EDDY_NORTH 6230.00 230KV CKT 1'	
'OASIS INTERCHANGE 230KV'	1.05899	0.9	1.05	'CHAVES COUNTY INTERCHANGE - SAN JUAN MESA TAP 230KV CKT 1'	
'PLEASANT HILL 230KV'	1.054475	0.9	1.05	'CHAVES COUNTY INTERCHANGE - EDDY_NORTH 6230.00 230KV CKT 1'	
'PLEASANT HILL 230KV'	1.055154	0.9	1.05	'CHAVES COUNTY INTERCHANGE - SAN JUAN MESA TAP 230KV CKT 1'	
'SAN JUAN MESA TAP 230KV'	1.100952	0.9	1.05	'CHAVES COUNTY INTERCHANGE - EDDY_NORTH 6230.00 230KV CKT 1'	
'SAN JUAN MESA TAP 230KV'	1.102297	0.9	1.05	'CHAVES COUNTY INTERCHANGE - SAN JUAN MESA TAP 230KV CKT 1'	
'SAN JUAN MESA TAP 230KV'	1.123706	0.9	1.05	'OASIS INTERCHANGE - SAN JUAN MESA TAP 230KV CKT 1'	

Results for GEN-2016-177 are preliminary. Final results will be posted in a later update.

CLUSTER GROUP 7 (SOUTHWESTERN OKLAHOMA AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C

The table below summarizes constraint and associated mitigation.

Table 8-13: Group 7 Cluster NRIS Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
CORNVILLE - NORGE ROAD 138KV CKT 1	136	102.04	System Intact	Rebuild Cornville – Norge Road 138kV CKT 1

CLUSTER GROUP 8 (NORTH OKLAHOMA/SOUTH CENTRAL KANSAS AREA)

Several ERIS non-converged constraints were observed for single contingency (N-1), and multi-contingency (P1, P2, etc.) conditions. The table below summarizes constraints and associated mitigations.

Table 8-14 Group 8 Cluster Non-Convergence ERIS Constraints

Monitored Elements	Mitigation
AXTELL - G16-050-TAP 345.00 345KV CKT 1	In addition to higher queued assigned upgrades the following new upgrades are required for group 8 potential voltage collapse: 1. Advance Geary Project NTC-200242 2. Install +300/-150 Mvar Static Var Compensator (SVC) at North Tulsa 345kV 3. Install +300/-100 Mvar SVC at the collector system facilities for GEN-2016-133, -134, -135, -136, -137,-138,-139,-140,-141,-142,-143,-144,-145, and -146.
CANEYRV7 345.00 - NEOSHO 345KV CKT 1	
DELAWARE - NORTHEAST STATION 345KV CKT 1	
EMPORIA ENERGY CENTER - G14_001T 345.00 345KV CKT 1	
EMPORIA ENERGY CENTER - SWISSVALE 345KV CKT 1	
FT SMITH - MUSKOGEE 345KV CKT 1	
G14_001T 345.00 - WICHITA 345KV CKT 1	
G15052_T 345.00 - OPENSKY7 345.00 345KV CKT 1	
G15052_T 345.00 - ROSE HILL 345KV CKT 1	
G15063_T 345.00 - MATHWSN7 345.00 345KV CKT 1	
G15063_T 345.00 - WOODRING 345KV CKT 1	
G16-050-TAP 345.00 - POST ROCK 345KV CKT 1	
G16-100-TAP 345.00 - SPRING CREEK 345KV CKT 1	
G16-111-TAP 345.00 - G16-122-TAP 345.00 345KV CKT 1	
G16-111-TAP 345.00 - RENO COUNTY 345KV CKT 1	
G16-122-TAP 345.00 - SUMMIT 345KV CKT 1	
G16133_345CS345.00 345KV SWITCHED SHUNT	
GEN300003 1-THOMAS HILL UNIT 3	
GEN300006 1-NEW MADRID UNIT 1	
GEN300007 1-NEW MADRID UNIT 2	
GEN509394 1-FLINT CREEK	
GEN511839 1-NORTHEASTERN STATION #2	
GEN512688 2-GRDA1 GSU2 22	
GEN542951 5-HAWTHORN UNIT #5	
GEN542955 1-LACYGNE UNIT #1	
GEN542956 2-LACYGNE UNIT #2	
GEN542957 1-IATAN UNIT #1	
GEN542962 2-IATAN UNIT #2	
GEN549893 2-SOUTHWEST 2	
GRDA1 - GREC TAP5 345.00 345KV CKT 1	
HOYT - JEFFREY ENERGY CENTER 345KV CKT 1	
HOYT - STRANGER CREEK 345KV CKT 1	

LACYGNE - STILWELL 345KV CKT 1	
LACYGNE - WAVERLY7 345.00 345KV CKT 1	
MINGO - RED WILLOW 345KV CKT 1	
NORTHEAST STATION - ONETA 345KV CKT 1	
NORTHEAST STATION - TULSA NORTH 345KV CKT 1	
NORTHWEST - SPRING CREEK 345KV CKT 1	
RANCHRD7 345.00 - SOONER 345KV CKT 1	
RENO COUNTY - WICHITA 345KV CKT 1	
RIVERSIDE STATION - SAPULPA ROAD 345KV CKT 1	
SAPULPA ROAD - WEKIWA 345KV CKT 1	
SWISSVALE - WEST GARDNER 345KV CKT 1	
T.NO.2-4 138.00 - TULSA NORTH 138KV CKT 1	
TULSA NORTH - WEKIWA 345KV CKT 1	
TULSA NORTH (TULSA N) 345/138/34.5KV TRANSFORMER CKT 1	
VIOLA 7 345.00 - WICHITA 345KV CKT 1	
WAVERLY7 345.00 - WOLF CREEK 345KV CKT 1	
G16133_765CS765.00 765/345KV TRANSFORMER CKT 1	In addition to higher queued assigned upgrades the following new upgrades are required for group 8 potential voltage collapse: 1. Advance Geary Project NTC-200242 2. Install +300/-150 Mvar Static Var Compensator (SVC) at North Tulsa 345kV 3. Install +300/-100 Mvar SVC at the collector system facilities for GEN-2016-133, -134, -135, -136, -137,-138,-139,-140,-141,-142,-143,-144,-145, and -146. 4. Power reduction for IC N-1 or third transformer for collector system and main substation transformer will be required. Proposed IC solution for these voltage related contingencies would be required to be review for SPP to mitigation of DISIS constraint.
G16133_765CS765.00 765/345KV TRANSFORMER CKT 2	
G16133_765TN765.00 765/345KV TRANSFORMER CKT 1	
G16133_765TN765.00 765/345KV TRANSFORMER CKT 2	

Several NRIS non-converged constraints were observed for single contingency (N-1), and multi-contingency (P1, P2, etc.) conditions. The table below summarizes constraints and associated mitigations.

Table 8-15 Group 8 Cluster Non-Convergence NRIS Constraints

Monitored Elements	Mitigation
7JASPER 345.00 - BLACKBERRY 345KV CKT 1	In addition to ERIS higher queued assigned upgrades the following new current study ERIS upgrades are required for group 8 potential voltage collapse: 1. Advance Geary Project NTC-200242 2. Install +300/-150 Mvar Static Var Compensator (SVC) at North Tulsa 345kV 3. Install +300/-100 Mvar SVC at the collector system facilities for GEN-2016-133, -134, -135, -136, -137,-138,-139,-140,-141,-142,-143,-144,-145, and -146.
7JASPER 345.00 - MORGAN 345KV CKT 1	
7SPORTSMAN - BLACKBERRY 345KV CKT 1	
ARCADIA - NORTHWEST 345KV CKT 1	
BARTLESVILLE COMANCHE - MOUND ROAD 138KV CKT 1	
BARTLESVILLE SOUTHEAST - NORTH BARTLESVILLE 138KV CKT 1	
BLACKBERRY - NEOSHO 345KV CKT 1	
CANEYRV7 345.00 - LATHAMS7 345.00 345KV CKT 1	
CANEYRV7 345.00 - NEOSHO 345KV CKT 1	
CHEROKEE DATA CENTER EAST TAP - OWAS88 138KV CKT 1	
CIMARRON - DRAPER LAKE 345KV CKT 1	
CLARKSVILLE - ONETA 345KV CKT 1	
CLEVELAND - G15066_T 345.00 345KV CKT 1	
COFFEYVILLE TAP - NORTH BARTLESVILLE 138KV CKT 1	
DOMES - MOUND ROAD 138KV CKT 1	
DOMES - PAWHUSKA TAP 138KV CKT 1	
EMPORIA ENERGY CENTER - G14_001T 345.00 345KV CKT 1	
EMPORIA ENERGY CENTER - SWISSVALE 345KV CKT 1	
G14_001T 345.00 - WICHITA 345KV CKT 1	
G15052_T 345.00 - OPENSKY7 345.00 345KV CKT 1	
G15052_T 345.00 - ROSE HILL 345KV CKT 1	
G15063_T 345.00 - MATHWSN7 345.00 345KV CKT 1	
G15063_T 345.00 - WOODRING 345KV CKT 1	
G16-063-TAP 345.00 - HUGO 345KV CKT 1	
G16-063-TAP 345.00 - SUNNYSIDE 345KV CKT 1	
G16-100-TAP 345.00 - SPRING CREEK 345KV CKT 1	
G16-122-TAP 345.00 - SUMMIT 345KV CKT 1	
GEARY 7 345.00 - SUMMIT 345KV CKT 1	
GEN336821 1-GRAND GULF UNIT	
GEN509394 1-FLINT CREEK	
GEN509403 1-PIRKEY GENERATION	
GEN511839 1-NORTHEASTERN STATION #2	
GEN511840 1-NORTHEASTERN STATION #3	
GEN512688 2-GRDA1 GSU2 22	
GEN532751 1-WOLF CREEK GENERATING STATION UNIT 1	
GRDA1 - GREC TAP5 345.00 345KV CKT 1	
GREC TAP5 345.00 - TULSA NORTH 345KV CKT 1	
LATHAMS7 345.00 - ROSE HILL 345KV CKT 1	
LAWTON EASTSIDE - TERRYRD7 345.00 345KV CKT 1	
LYDIA - VALLIANT 345KV CKT 1	
LYDIA - WELSH 345KV CKT 1	
MORISNT4 138.00 - STILLWATER 138KV CKT 1	
NORTHEAST STATION - ONETA 345KV CKT 1	
NORTHEAST STATION - OWASSO 109TH STREET 138KV CKT 1	
NORTHEAST STATION - TULSA NORTH 138KV CKT 1	
NORTHEAST STATION - TULSA NORTH 345KV CKT 1	
NORTHWEST - SPRING CREEK 345KV CKT 1	
OPENSKY7 345.00 - RANCHRD7 345.00 345KV CKT 1	
OSAGE - WEBB CITY TAP 138KV CKT 1	
OWASSO 109TH STREET - OWASSO NORTH TAP 138KV CKT 1	
OWASSO NORTH TAP - TULSA NORTH 138KV CKT 1	

Monitored Elements	Mitigation
PAWHUSKA TAP - WEST PAWHUSKA 138KV CKT 1	
PECAN CREEK - RIVERSIDE STATION 345KV CKT 1	
PITTSBURG - SEMINOLE 345KV CKT 1	
PITTSBURG - VALLIANT 345KV CKT 1	
RIVERSIDE STATION - SAPULPA ROAD 345KV CKT 1	
SAPULPA ROAD - WEKIWA 345KV CKT 1	
SHIDLER - WEST PAWHUSKA 138KV CKT 1	
SPVALLY4 138.00 - STILLWATER 138KV CKT 1	
SUNNYSIDE - TERRYRD7 345.00 345KV CKT 1	
SWISSVALE - WEST GARDNER 345KV CKT 1	
T.NO.2-4 138.00 - TULSA NORTH 138KV CKT 1	
TULSA NORTH - WEKIWA 345KV CKT 1	
TULSA NORTH (TULSA N) 345/138/34.5KV TRANSFORMER CKT 1	
G16133_765CS765.00 765/345KV TRANSFORMER CKT 1	In addition to higher queued assigned upgrades the following new Current Study ERIS upgrades are required for group 8 potential voltage collapse: 1. Advance Geary Project NTC-200242 2. Install +300/-150 Mvar Static Var Compensator (SVC) at North Tulsa 345kV 3. Install +300/-100 Mvar SVC at the collector system facilities for GEN-2016-133, -134, -135, -136, -137,-138,-139,-140,-141,-142,-143,-144,-145, and -146. 4. Power reduction for IC N-1 or third transformer for collector system and main substation transformer will be required. Proposed IC solution for these voltage related contingencies would be required to be review for SPP to mitigation of DISIS constraint.
G16133_765CS765.00 765/345KV TRANSFORMER CKT 2	
G16133_765TN765.00 765/345KV TRANSFORMER CKT 1	
G16133_765TN765.00 765/345KV TRANSFORMER CKT 2	

Several ERIS thermal constraints were observed for single contingency (N-1), and multi-contingency (P1, P2, etc.) conditions. The table below summarizes constraints and associated mitigations. The table below summarizes constraints and associated mitigations.

Table 8-16 Group 8 Cluster ERIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
4REMNGTON 138.00 - ASGI1708TP 138.00 138KV CKT 1	213.0	120.2206	SHIDLER - WEST PAWHUSKA 138KV CKT 1	Upgrade Remington-Shidler 138 kV line to 1192.5 ACSR at 100 C
4REMNGTON 138.00 - FAIRFAX 138KV CKT 1	217.0	133.0496	System Intact	Upgrade Remington-Fairfax 138 kV line to 1590 ACSR at 100 C
4REMNGTON 138.00 - FAIRFAX 138KV CKT 1	217.0	190.0555	SHIDLER - WEST PAWHUSKA 138KV CKT 1	
BARTLESVILLE COMANCHE - BARTLESVILLE SOUTHEAST 138KV CKT 1	153	127.9684	4REMNGTON 138.00 - FAIRFAX 138KV CKT 1	Rebuild approximately 5 miles of 138kV assigned to higher queued AECI project (GIA-59)
FAIRFAX 138/69KV TRANSFORMER CKT 1	56.0	153.5289	System Intact	Upgrade the Fairfax 138/69 kV 56 MVA transformer to two 84 MVA units
BARTLESVILLE COMANCHE - MOUND ROAD 138KV CKT 1	131.0	173.601	System Intact	Rebuild approximately 45 miles of 138kV assigned to higher queued AECI project (GIA-59)
BARTLESVILLE COMANCHE - MOUND ROAD 138KV CKT 1	131.0	226.0955	4REMNGTON 138.00 - FAIRFAX 138KV CKT 1	
DOMES - MOUND ROAD 138KV CKT 1	189.0	130.1181	System Intact	
DOMES - MOUND ROAD 138KV CKT 1	189.0	185.1161	4REMNGTON 138.00 - FAIRFAX 138KV CKT 1	
DOMES - PAWHUSKA TAP 138KV CKT 1	189.0	135.0301	System Intact	
DOMES - PAWHUSKA TAP 138KV CKT 1	189.0	190.2539	4REMNGTON 138.00 - FAIRFAX 138KV CKT 1	
DOMES - PAWHUSKA TAP 138KV CKT 1	357.0	106.5016	4REMNGTON 138.00 - FAIRFAX 138KV CKT 1	
PAWHUSKA TAP - WEST PAWHUSKA 138KV CKT 1	189.0	139.3717	System Intact	
PAWHUSKA TAP - WEST PAWHUSKA 138KV CKT 1	189.0	194.8696	4REMNGTON 138.00 - FAIRFAX 138KV CKT 1	
SHIDLER - WEST PAWHUSKA 138KV CKT 1	181.0	147.1323	System Intact	
SHIDLER - WEST PAWHUSKA 138KV CKT 1	189.0	196.5191	4REMNGTON 138.00 - FAIRFAX 138KV CKT 1	
BENTON - WICHITA 345KV CKT 1	956.0	114.2609	LACYGNE - WAVERLY7 345.00 345KV CKT 1	Replace terminal equipment
ELPASOE4 138.00 - FARBER 138KV CKT 1	287.0	105.8275	P23:345:WERE:WICH_345-116::-BUFFALOFLATS	Replace terminal equipment
FARBER - SUMNER COUNTY NO. 10 BELLE PLAIN 138KV CKT 1	314.0	102.3217	P23:345:WERE:WICH_345-116::-BUFFALOFLATS	Rebuild assigned to higher queued DISIS-2016-001

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
				Interconnection Customer(s)
G15063_T 345.00 - MATHWSN7 345.00 345KV CKT 1	1192.0	122.5143	System Intact	In addition to higher queued group 8 assigned upgrades the following are required for mitigation: 1. Build Woodring – G15-063Tap (Redington) 345kV CKT 2 2. Build Redington – Spring Creek 345kV CKT 1 3. Northwest – Spring Creek 345kV CKT 2 4. Replace terminal equipment for Northwest – Spring Creek 345kV CKT 1 per DISIS-2016-001-1 assignment
G15063_T 345.00 - MATHWSN7 345.00 345KV CKT 1	1192.0	165.5665	G16-100-TAP 345.00 - SPRING CREEK 345KV CKT 1	
G15063_T 345.00 - MATHWSN7 345.00 345KV CKT 1	1541.0	146.4519	NORTHWEST - SPRING CREEK 345KV CKT 1	
G15063_T 345.00 - WOODRING 345KV CKT 1	1195.0	140.5221	G16-100-TAP 345.00 - SPRING CREEK 345KV CKT 1	
G16-100-TAP 345.00 - SPRING CREEK 345KV CKT 1	1039.0	122.4951	System Intact	
G16-100-TAP 345.00 - SPRING CREEK 345KV CKT 1	1195.0	148.4997	G15063_T 345.00 - MATHWSN7 345.00 345KV CKT 1	
NORTHWEST - SPRING CREEK 345KV CKT 1	1342.0	112.973	System Intact	
NORTHWEST - SPRING CREEK 345KV CKT 1	1540.0	153.3887	G15063_T 345.00 - MATHWSN7 345.00 345KV CKT 1	
HUNTERS7 345.00 - WOODRING 345KV CKT 1	1195.0	116.2688	VIOLA 7 345.00 - WICHITA 345KV CKT 1	Build Hunter – Woodring 345kV CKT 2
VIOLA 7 345.00 - WICHITA 345KV CKT 1	1076.0	104.1027	System Intact	1. Viola Project 345/138kV per NTC-200228, 200296, 200362. 2. Build Viola – Buffalo Flats 345kV CKT 1
VIOLA 7 345.00 - WICHITA 345KV CKT 1	1076	139.3553	HUNTERS7 345.00 - WOODRING 345KV CKT 1	
VIOLA 7 345.00 (VIOLA TX-1) 345/138/13.8KV TRANSFORMER CKT 1	440.0	166.5387	P23:345:WERE:WICH_345-116::-BUFFALOFLATS	
G16133_765CS765.00 - G16133_765R3765.00 765KV CKT 1	2000.0	123.1937	System Intact	Interconnection Customer(s) facilities. IC will have to provide mitigation (equipment upgrade, ratings verifications) for constraints.
G16133_765CS765.00 - G16133_765R3765.00 765KV CKT 1	2000.0	125.9727	G15063_T 345.00 - WOODRING 345KV CKT 1	
G16133_765R1765.00 - G16133_765TN765.00 765KV CKT 1	2000.0	122.6919	System Intact	
G16133_765R1765.00 - G16133_765TN765.00 765KV CKT 1	2000.0	124.5485	CANEYRV7 345.00 - NEOSHO 345KV CKT 1	
G16133G16146345.00 - TULSA NORTH 345KV CKT 1	2000.0	120.0423	System Intact	
G16133G16146345.00 - TULSA NORTH 345KV CKT 1	2000.0	122.4122	LACYGNE - WAVERLY7 345.00 345KV CKT 1	
GRDA1 - GREC TAP5 345.00 345KV CKT 1	901.0	141.9681	System Intact	Replace terminal equipment
GRDA1 - GREC TAP5 345.00 345KV CKT 1	1055.0	123.9508	TULSA NORTH - WEKIWA 345KV CKT 1	

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
HARDY 4 138.00 - WEBBCTY4 138.00 138KV CKT 1	138.0	106.211	System Intact	Rebuild/Re-conductor approximately 2 miles of 138kV
SHIDWFC4 138.00 - WEBB CITY TAP 138KV CKT 1	117.0	114.1108	System Intact	Rebuild/Re-conductor approximately 2.5 miles of 138kV
SHIDWFC4 138.00 - WEBBCTY4 138.00 138KV CKT 1	117.0	120.4404	System Intact	Rebuild/Re-conductor approximately 13 miles of 138kV
OSAGE - WEBB CITY TAP 138KV CKT 1	287.0	105.8274	4REMNGTON 138.00 - FAIRFAX 138KV CKT 1	Rebuild assigned to DISIS-2016-001 Interconnection Customer(s)
KELLY - KING HILL N.M. COOP (NEMAHA MARSHALL R.E.C. 115KV CKT 1	92.0	103.5361	CLIFTON - CONCORDIA 115KV CKT 1	1. Iatan – Stranger Creek 161kV Voltage Conversion to 345 NTC-200328 and 200337. 2. Geary Project. NTC-200242
LACYGNE - WAVERLY7 345.00 345KV CKT 1	1141.0	116.0886	System Intact	Replace terminal equipment to achieve conductor element
LACYGNE - WAVERLY7 345.00 345KV CKT 1	1254.0	111.4018	BENTON - WICHITA 345KV CKT 1	
RENFROW4 138.00 - RENFROW4 138.00 138KV CKT 1	183.0	118.1338	System Intact	Rebuild/Re-conductor approximately 2 miles of 138kV
RENFROW4 138.00 - WAKITA_138 138.00 138KV CKT 1	183.0	114.5556	System Intact	Rebuild/Re-conductor approximately 17 miles of 138kV
SPVALLY4 138.00 - STILLWATER 138KV CKT 1	194.0	102.5738	System Intact	1. Build Woodring – G15-063Tap (Redington) 345kV CKT 2 2. Build Redington – Spring Creek 345kV CKT 1
TULSA NORTH - WEKIWA 345KV CKT 1	1182.0	102.1011	GRDA1 - GREC TAP5 345.00 345KV CKT 1	Rebuild/Re-conductor approximately 17.5 miles of 345kV
TULSA NORTH (TULSA N) 345/138/34.5KV TRANSFORMER CKT 1	675.0	113.8817	System Intact	Install second 345/138kV transformer
TULSA NORTH (TULSA N) 345/138/34.5KV TRANSFORMER CKT 1	742.0	125.5404	TULSA NORTH - WEKIWA 345KV CKT 1	
WAVERLY7 345.00 - WOLF CREEK 345KV CKT 1	1141.0	99.5	System Intact	1. Iatan – Stranger Creek 161kV Voltage Conversion to 345 NTC-200328 and 200337. 2. Geary Project. NTC-200242 3. Viola – Buffalo Flats 345kV CKT 1
WAVERLY7 345.00 - WOLF CREEK 345KV CKT 1	1195.0	101.1065	BENTON - WICHITA 345KV CKT 1	

Several NRIS thermal constraints were observed for single contingency (N-1), and multi-contingency (P1, P2, etc.) conditions. The table below summarizes constraints and associated mitigations. The table below summarizes constraints and associated mitigations.

Table 8-17 Group 8 Cluster NRIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
4REMNGTON 138.00 - ASGI1708TP 138.00 138KV CKT 1	174.0	147.0969	SHIDLER - WEST PAWHUSKA 138KV CKT 1	Mitigated by ERIS Upgrade: Remington-Shidler 138 kV line to 1192.5 ACSR at 100 C
4REMNGTON 138.00 - FAIRFAX 138KV CKT 1	212.0	120.1947	System Intact	Mitigated by ERIS Upgrade: Remington-Fairfax 138 kV line to 1590 ACSR at 100 C
4REMNGTON 138.00 - FAIRFAX 138KV CKT 1	212.0	170.253	SHIDLER - WEST PAWHUSKA 138KV CKT 1	
BARTLESVILLE COMANCHE - BARTLESVILLE SOUTHEAST 138KV CKT 1	153.0	116.107	4REMNGTON 138.00 - FAIRFAX 138KV CKT 1	Mitigated by ERIS Upgrade: Rebuild approximately 5 miles of 138kV assigned to higher queued AECI project (GIA-59)
BARTLESVILLE COMANCHE - MOUND ROAD 138KV CKT 1	131.0	122.7703	System Intact	Rebuild approximately 45 miles of 138kV assigned to higher queued AECI project (GIA-59)
BARTLESVILLE COMANCHE - MOUND ROAD 138KV CKT 1	131.0	191.8509	4REMNGTON 138.00 - FAIRFAX 138KV CKT 1	
DOMES - MOUND ROAD 138KV CKT 1	189.0	111.8173	System Intact	
DOMES - MOUND ROAD 138KV CKT 1	189.0	161.4663	4REMNGTON 138.00 - FAIRFAX 138KV CKT 1	
DOMES - PAWHUSKA TAP 138KV CKT 1	189.0	114.5698	System Intact	
DOMES - PAWHUSKA TAP 138KV CKT 1	189.0	164.2834	4REMNGTON 138.00 - FAIRFAX 138KV CKT 1	
PAWHUSKA TAP - WEST PAWHUSKA 138KV CKT 1	189.0	118.803	System Intact	
PAWHUSKA TAP - WEST PAWHUSKA 138KV CKT 1	189.0	168.6955	4REMNGTON 138.00 - FAIRFAX 138KV CKT 1	
SHIDLER - WEST PAWHUSKA 138KV CKT 1	181.0	124.9734	System Intact	
SHIDLER - WEST PAWHUSKA 138KV CKT 1	189.0	102.0788	4REMNGTON 138.00 - FAIRFAX 138KV CKT 1	
FAIRFAX 138/69KV TRANSFORMER CKT 1	56.0	135.5407	System Intact	Mitigated by ERIS Upgrade: Upgrade the Fairfax 138/69 kV 56 MVA transformer to two 84 MVA units
FAIRFAX 138/69KV TRANSFORMER CKT 1	56.0	186.4159	FAIRFAX - PAWNSW4 138.00 138KV CKT 1	
ALTOONA - BUTLER 138KV CKT 1	101.0	113.4864	LACYGNE - WAVERLY7 345.00 345KV CKT 1	Build approximately 95 miles of Wolf Creek – Neosho 345kV CKT 1
MIDIAN (MIDI TX-1) 138/69/13.2KV TRANSFORMER CKT 1	110.0	106.6399	BUTLER - MIDIAN 138KV CKT 1	
CANEYRV7 345.00 - NEOSHO 345KV CKT 1	923.0	101.5129	LACYGNE - WAVERLY7 345.00 345KV CKT 1	
WAVERLY7 345.00 - WOLF CREEK 345KV CKT 1	1195.0	103.9609	CANEYRV7 345.00 - NEOSHO 345KV CKT 1	

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
LACYGNE - WAVERLY7 345.00 345KV CKT 1	1254.0	111.4434	CANEYRV7 345.00 - NEOSHO 345KV CKT 1	
BUTLER - MIDIAN 138KV CKT 1	143.0	108.1228	MIDIAN (MIDI TX-1) 138/69/13.2KV TRANSFORMER CKT 1	Build approximately 95 miles of Wolf Creek – Neosho 345kV CKT 1 and replace terminal equipment
ANADARKO - GRACMNT4 138.00 138KV CKT 1	200.0	104.2448	System Intact	Rebuild/Re-conductor approximately 5 miles of 138kV
ANADARKO - GRACMNT4 138.00 138KV CKT 1	234.0	115.5412	ANADARKO - SOUTHWESTERN STATION 138KV CKT 1	
BARTLESVILLE COMANCHE - BLUESTEM 138KV CKT 1	131.0	103.6094	BARTLESVILLE COMANCHE - BARTLESVILLE SOUTHEAST 138KV CKT 1	Build second Bartlesville – Bartlesville SE 138kV circuit #2
BENTON (BENT TX-1) 345/138/13.8KV TRANSFORMER CKT 1	440.0	106.6478	BENTON (BENT TX-2) 345/138/13.8KV TRANSFORMER CKT 1	Install Benton 345/138/13kV Transformer CKT 3
BENTON (BENT TX-2) 345/138/13.8KV TRANSFORMER CKT 1	440.0	103.989	BENTON (BENT TX-1) 345/138/13.8KV TRANSFORMER CKT 1	
CATOOSA - OWASS88 138KV CKT 1	210.0	101.4125	GRDA1 - GREC TAP5 345.00 345KV CKT 1	Rebuild/re-conductor 10 miles of 138kV
CHEROKEE DATA CENTER EAST TAP - OWASS88 138KV CKT 1	211.0	106.6425	GRDA1 - GREC TAP5 345.00 345KV CKT 1	Rebuild/re-conductor 2.5 miles of 138kV
CHEROKEE DATA CENTER EAST TAP - TULSA NORTH 138KV CKT 1	168.0	108.2759	System Intact	Rebuild/re-conductor 4 miles of 138kV
CHEROKEE DATA CENTER EAST TAP - TULSA NORTH 138KV CKT 1	209.0	120.5498	GRDA1 - GREC TAP5 345.00 345KV CKT 1	
CIMARRON (CIMARON1) 345/138/13.8KV TRANSFORMER CKT 1	382.0	116.151	CIMARRON (CIMARON2) 345/138/13.8KV TRANSFORMER CKT 1	Install 3rd transformer
CIMARRON (CIMARON2) 345/138/13.8KV TRANSFORMER CKT 1	382.0	119.9686	CIMARRON (CIMARON1) 345/138/13.8KV TRANSFORMER CKT 1	
CITY OF WINFIELD - RAINBOW 69KV CKT 1	43	119.2238	OAK - STROTHER FIELD (CITY OF WINFIELD) 69KV CKT 1	Rebuild/Re-conductor approximately 5 miles 69kV
OAK - RAINBOW 69KV CKT 1	43.0	122.1591	OAK - STROTHER FIELD (CITY OF WINFIELD) 69KV CKT 1	
G15063_T 345.00 - MATHWSN7 345.00 345KV CKT 1	1192.0	126.4527	G16-100-TAP 345.00 - SPRING CREEK 345KV CKT 1	Mitigated by the following ERIS upgrades: 1. Build Woodring – G15-063Tap (Redington) 345kV CKT 2 2. Build Redington – Spring Creek 345kV CKT 1 3. Hunter – Woodring 345kV CKT 2
G15063_T 345.00 - WOODRING 345KV CKT 1	1195.0	106.5606	G16-100-TAP 345.00 - SPRING CREEK 345KV CKT 1	
G16-100-TAP 345.00 - SPRING CREEK 345KV CKT 1	1039.0	102.6238	System Intact	
G16-100-TAP 345.00 - SPRING CREEK 345KV CKT 1	1195.0	121.3972	G15063_T 345.00 - MATHWSN7 345.00 345KV CKT 1	
VIOLA 7 345.00 - WICHITA 345KV CKT 1	1076.0	113.5549	G15052_T 345.00 - ROSE HILL 345KV CKT 1	
CRESWELL - MIDLTNT4 138.00 138KV CKT 1	222.0	103.0441	P23:345:WERE:WICH_345-116::-BUFFALOFLATS'	

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
VIOLA 7 345.00 (VIOLA TX-1) 345/138/13.8KV TRANSFORMER CKT 1	440.0	117.9047	P23:345:WERE:WICH_345-116::-BUFFALOFLATS	4. Viola – Buffalo Flats 345kV CKT 1 5. Northwest – Spring Creek 345kV CKT 2 6. Replace terminal equipment for Northwest – Spring Creek 345kV CKT 1 per DISIS-2016-001-1 assignment
EVANS ENERGY CENTER NORTH - SEDGWICK COUNTY NO. 12 COLWICH 138KV CKT 1	191.0	105.1446	RENO COUNTY - WICHITA 345KV CKT 1	Updated rating for Evan - Sedgwick
G16-032-TAP 345.00 345/138KV TRANSFORMER CKT 1	194.0	123.6013	System Intact	Interconnection Customer facility
G16-032-TAP 345.00 345/138KV TRANSFORMER CKT 1	222.0	139.6542	G15063_T 345.00 - MATHWSN7 345.00 345KV CKT 1	
G16133_765CS765.00 - G16133_765R3765.00 765KV CKT 1	2000.0	121.4655	System Intact	Interconnection Customer(s) facilities. IC will have to provide mitigation (equipment upgrade, ratings verifications) for constraints.
G16133_765CS765.00 - G16133_765R3765.00 765KV CKT 1	2000.0	125.687	G16133_765CS765.00 765/345KV TRANSFORMER CKT 1	
G16133_765R1765.00 - G16133_765TN765.00 765KV CKT 1	2000.0	122.5592	System Intact	
G16133_765R1765.00 - G16133_765TN765.00 765KV CKT 1	2000.0	124.2527	GRDA1 - GREC TAP5 345.00 345KV CKT 1	
G16133G16146345.00 - TULSA NORTH 345KV CKT 1	2000.0	119.4968	System Intact	
G16133G16146345.00 - TULSA NORTH 345KV CKT 1	2000.0	121.3382	GRDA1 - GREC TAP5 345.00 345KV CKT 1	
GRDA1 - GREC TAP5 345.00 345KV CKT 1	901.0	137.0632	System Intact	Replace terminal equipment
GRDA1 - GREC TAP5 345.00 345KV CKT 1	1055.0	131.8392	CHAMBER SPRINGS - CLARKSVILLE 345KV CKT 1	
BRISTOW - SILVER CITY 138KV CKT 1	114.0	104.203	OSAGE - WEBB CITY TAP 138KV CKT 1	Change out relays
OSAGE - WEBB CITY TAP 138KV CKT 1	287.0	102.6976	4REMNGTON 138.00 - FAIRFAX 138KV CKT 1	DISIS-2016-001-1 assigned upgrade
PITTSBURG - SEMINOLE 345KV CKT 1	717	99.6	CANADIAN RIVER - MUSKOGEE 345KV CKT 1	Updated rating is sufficient for this study's mitigation
RENO COUNTY (RENO TX-2) 345/115/14.4KV TRANSFORMER CKT 1	308.0	117.9397	P23:345:WERE:RENO_345-140::G16111TAP	Build 3rd transformer
SAND SPRINGS - SHEFFIELD 138KV CKT 1	156.0	106.0481	System Intact	Rebuild/Re-conductor approximately 1 mile of 138kV
SAND SPRINGS - SHEFFIELD 138KV CKT 1	202.0	133.7775	SAPULPA ROAD - WEKIWA 345KV CKT 1	

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
SHEFFIELD - WEKIWA 138KV CKT 1	156	106.363	System Intact	Rebuild/Re-conductor approximately 7.5 miles of 138kV
SHEFFIELD - WEKIWA 138KV CKT 1	173	153.734	SAPULPA ROAD - WEKIWA 345KV CKT 1	
SILOAM CITY - SILOAM SPRINGS 161KV CKT 1	317.0	158.4859	FLINT CREEK - SILOAM SPRINGS TAP 345KV CKT 1	Rebuild/re-conductor 2 miles of 161kV
SILOAM CITY - SILOAM SPRINGS TAP 161KV CKT 1	286.0	135.5888	FLINT CREEK - SILOAM SPRINGS TAP 345KV CKT 1	Upgrade terminal equipment
SILOAM SPRINGS TAP (TONNEC345) 345/161/13.8KV TRANSFORMER CKT 1	350.0	117.6236	FLINT CREEK - SILOAM SPRINGS TAP 345KV CKT 1	Build second Siloam Springs Tap (Tonnece) transformer
HARDY 4 138.00 - WEBBCTY4 138.00 138KV CKT 1	138.0	105.8156	System Intact	Rebuild/Re-conductor approximately 2 miles of 138kV
SHIDWFC4 138.00 - WEBB CITY TAP 138KV CKT 1	117.0	113.9112	System Intact	Mitigated by ERIS Upgrade: Rebuild/Re-conductor approximately 2.5 miles of 138kV
SHIDWFC4 138.00 - WEBBCTY4 138.00 138KV CKT 1	117.0	120.126	System Intact	Mitigated by ERIS Upgrade: Rebuild/Re-conductor approximately 13 miles of 138kV
TULSA NORTH (TULSA N) 345/138/34.5KV TRANSFORMER CKT 1	675.0	108.6503	System Intact	Mitigated by ERIS Upgrade: Install second 345/138kV transformer
TULSA NORTH (TULSA N) 345/138/34.5KV TRANSFORMER CKT 1	742.0	129.6571	GRDA1 - GREC TAP5 345.00 345KV CKT 1	

The following requests will require an Affected System review from AECI:

GEN-2016_091	GEN-2016_128	GEN-2016_143
GEN-2016_100	GEN-2016_133	GEN-2016_144
GEN-2016_101	GEN-2016_134	GEN-2016_145
GEN-2016_118	GEN-2016_137	GEN-2016_146
GEN-2016_119	GEN-2016_138	GEN-2016_148
GEN-2016_120	GEN-2016_141	GEN-2016_162
GEN-2016_127	GEN-2016_142	GEN-2016_163

The table below summarizes constraints and associated mitigations assignable to incremental ERIS steady state voltage. The steady state voltage constraints for mitigation are identified incremental to the thermal constraint mitigations.

Table 8-18 Group 8 Cluster ERIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
7JASPER 345.00 345KV	0.876186	0.95	1.05	LACYGNE - WAVERLY7 345.00 345KV CKT 1	Existing Benton capacitor bank switched on, current study thermal upgrades, and install Neosho 200 Mvar Capacitor Bank
87th STREET 345KV	0.944269	0.95	1.05	P55:345:KCPL:STILWELL_BUS_22	
BENTON 345KV	0.93601	0.95	1.05	LACYGNE - WAVERLY7 345.00 345KV CKT 1	
CANEYRV7 345.00 345KV	0.883056	0.95	1.05	LACYGNE - WAVERLY7 345.00 345KV CKT 1	
NEOSHO 345KV	0.861014	0.95	1.05	LACYGNE - WAVERLY7 345.00 345KV CKT 1	
WICHITA 345KV	0.942535	0.95	1.05	LACYGNE - WAVERLY7 345.00 345KV CKT 1	
G16-153-TAP 345.00 345KV	0.930411	0.90	1.05	LACYGNE - WAVERLY7 345.00 345KV CKT 1	Viola project, current study thermal upgrades, and reactive power requirement (Order 827)
GEN-2016-153345.00 345KV	0.949951	0.90	1.05	LACYGNE - WAVERLY7 345.00 345KV CKT 1	IC facility mitigation
GEN-2016-162345.00 345KV	0.947625	0.90	1.05	LACYGNE - WAVERLY7 345.00 345KV CKT 1	
GEN-2016-163345.00 345KV	0.949158	0.90	1.05	LACYGNE - WAVERLY7 345.00 345KV CKT 1	
GEN-2016-057345.00 345KV	1.091346	0.90	1.05	MATHWSN7 345.00 - NORTHWEST 345KV CKT 1	
ZONE-1 SUB 345.00 345KV	1.052324	0.90	1.05	G16133_765CS765.00 765/345KV TRANSFORMER CKT 1	
ZONE-2 SUB 345.00 345KV	1.052314	0.90	1.05	G16133_765CS765.00 765/345KV TRANSFORMER CKT 1	
ZONE-4 SUB 345.00 345KV	1.052633	0.90	1.05	G16133_765CS765.00 765/345KV TRANSFORMER CKT 1	
ZONE-5 SUB 345.00 345KV	1.051285	0.90	1.05	G16133_765CS765.00 765/345KV TRANSFORMER CKT 1	
ZONE-6 SUB 345.00 345KV	1.051789	0.90	1.05	G16133_765CS765.00 765/345KV TRANSFORMER CKT 1	

The table below summarizes constraints and associated mitigations assignable to incremental NRIS steady state voltage. The steady state voltage constraints for mitigation are identified incremental to the thermal constraint mitigations.

Table 8-19 Group 8 Cluster NRIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
G16-045-SUB2345.00 345KV	1.088014	0.9	1.05	GEN588097 1-G7 0.69 0.6900	GEN-2016-133 through GEN-2016-146 IC facility reactive power mitigation
G16133_345CS345.00 345KV	1.121134	0.9	1.05	GEN588057 1-G9 0.69 0.6900	
G16133_765CS765.00 765KV	1.125528	0.9	1.05	GEN588097 1-G7 0.69 0.6900	

G16133_765R2765.00 765KV	1.113902	0.9	1.05	GEN588097 1-G7 0.69 0.6900	
G16133_765R3765.00 765KV	1.125528	0.9	1.05	GEN588097 1-G7 0.69 0.6900	
G16-045-SUB2345.00 345KV	1.122185	0.9	1.05	GEN588097 1-G7 0.69 0.6900	
ZONE-1 SUB 345.00 345KV	1.122181	0.9	1.05	GEN588097 1-G7 0.69 0.6900	
ZONE-2 SUB 345.00 345KV	1.121142	0.9	1.05	GEN588097 1-G7 0.69 0.6900	
ZONE-3 SUB 345.00 345KV	1.121207	0.9	1.05	GEN588097 1-G7 0.69 0.6900	
ZONE-4 SUB 345.00 345KV	1.122203	0.9	1.05	GEN588097 1-G7 0.69 0.6900	
ZONE-5 SUB 345.00 345KV	1.121841	0.9	1.05	GEN588097 1-G7 0.69 0.6900	
ZONE-6 SUB 345.00 345KV	1.122185	0.9	1.05	GEN588097 1-G7 0.69 0.6900	

CLUSTER GROUP 9 (NEBRASKA AREA)

Generation in this area may require additional upgrades to relieve system reliability constraints related to NERC registered flowgates #5221, #6006, #6007, & #6008. These flowgates require additional review and updates resultant from the inclusion of the assigned network upgrades.

New requests for this study group as well as prior-queued requests are listed in Appendix C

Below is a list of the upgrades assigned, and the corresponding scenarios in which these upgrades were assigned. Scenario numbers are denoted as "S#".

Table 8-20 Group 9 Cluster Upgrade Scenarios

Scenario	Incremental Mitigation
0	None
2	Addition of Keystone to Red Willow 345kV circuit #1
	Addition of Post Rock to Red Willow 345kV circuit #1
	Reroute Laramie River Station (GEN-2016-110-Tap) to Stegall 345kV circuit #1 through the GEN-2016-023-Tap substation
3	Build GEN-2016-023-Tap substation to Stegall 345kV circuit #2
4	Addition of Antelope to Grand Prairie 345kV circuit #1
	Install +100 MVAR SVC at Keystone 345kV
	Install 20.0MVAR Atwood Switch 115kV switched shunt capacitor
	Install 10.0MVAR Heizer 69kV switched shunt capacitor
	Install 50.0MVAR Mingo 115kV switched shunt capacitor
	Install 30.0MVAR PH Run 115kV switched shunt capacitor

ERIS and NRIS non-converged constraints were observed for single contingency (N-1), and multi-contingency (P1, P2, etc.) conditions. The tables below summarize constraints and associated mitigations.

Table 8-21 Group 9 Cluster Non-Convergence ERIS Constraints

Contingent Elements	Mitigation
'AXTELL - G16-050-TAP 345.00 345KV CKT 1'	1. Build Keystone – Red Willow 345kV Ckt 1 2. Build Red Willow – Caprock 345kV Ckt1 3. Reroute Laramie River Station (GEN-2016-110-Tap) to Stegall 345kV circuit #1 through the GEN-2016-023-Tap substation
'AXTELL - PAULINE 345KV CKT 1'	
'AXTELL - SWEETWATER 345KV CKT 1'	
'BANNER_CO 345.00 - G1623&1629-T345.00 345KV CKT 1'	
'BANNER_CO 345.00 - KEYSTONE 345KV CKT 1'	
'BANNER_CO 345.00 - SIDNEY2-LNX3345.00 345KV CKT 1'	
'CROOKED CREEK - NORTH PLATTE 230KV CKT 1'	
'FT THOMPSON - FTTHOM2-LNX3345.00 345KV CKT Z'	
'FTTHOM2-LNX3345.00 - GRPRAR2-LNX3345.00 345KV CKT 1'	
'FTTHOMPSON-GRANDPRAIRIE-TLINE-REACTOR-CKT1'	
'G15088_T 345.00 - G16-096-TAP 345.00 345KV CKT 1'	
'G15088_T 345.00 - MOORE 345KV CKT 1'	
'G16-050-TAP 345.00 - POST ROCK 345KV CKT 1'	
'G16-110-TAP 345.00 - LARAMIE RIVER 345KV CKT 1'	
'G16-110-TAP 345.00 - STEGALL 345KV CKT 1'	
'GEN344225 1-1CAL G1 25.000'	
'GERALD GENTLEMAN STATION - RED WILLOW 345KV CKT 1'	
'GERALD GENTLEMAN STATION - SWEETWATER 345KV CKT 1'	
'GERALD GENTLEMAN STATION - SWEETWATER 345KV CKT 2'	
'GR ISLD3 345.00 - MCCOOL 345KV CKT 1'	
'GR ISLD3 345.00 - SWEETWATER 345KV CKT 1'	
'GR ISLD-LNX3345.00 - GR ISLD3 345.00 345KV CKT Z'	
'GR ISLD-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1'	
'GRANDPRAIRIE-FTTHOMPSON-TLINE-REACTORS-CKT1'	
'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
'HOLCOMB - SETAB 345KV CKT 1'	
'HOLT 7 345.00 - MULLNCR7 345.00 345KV CKT 1'	
'HOLT 7 345.00 - SUB 3458 NEB CTY 345KV CKT 1'	
'KETCHEM7 345.00 - MULLNCR7 345.00 345KV CKT 1'	
'KETCHEM7 345.00 - SIBLEY 345KV CKT 1'	
'KEYSTONE - SIDNEY1-LNX3345.00 345KV CKT 1'	
'MCCOOL - MOORE 345KV CKT 1'	
'MINGO - RED WILLOW 345KV CKT 1'	
'MINGO - SETAB 345KV CKT 1'	
'NUNDRWD - WAYSIDE 230KV CKT 1'	
'SIDNEY-KEYSTONE-TLINE-REACTORS-CKT1'	
'STEGALL - STEGALL-LNX3230.00 230KV CKT Z'	
'STEGALL-LNX3230.00 - WAYSIDE 230KV CKT 1'	
'STEGALL-WAYSIDE-TLINE-REACTOR-CKT1'	

Table 8-22 Group 9 Cluster Non-Convergence NRIS Constraints

All non-converged constraints are mitigated by ERIS assigned upgrades.

Several ERIS thermal constraints were observed for single contingency (N-1), and multi-contingency (P1, P2, etc.) conditions. The table below summarizes constraints and associated mitigations.

Table 8-223 Group 9 Cluster ERIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
'BAILEYVILLE N.M. STATION (NEMAHA MARSHALL R - SMITTYVILLE N.M. COOP (NEMAHA MARSHALL R.E. 115KV CKT 1'	92	139.3618	'CLIFTON - CONCORDIA 115KV CKT 1'	1. Add Keystone – Red Willow 345kV 2. Add Red Willow – Post Rock 345kV
'BAILEYVILLE N.M. STATION (NEMAHA MARSHALL R - SOUTH SENECA 115KV CKT 1'	92	141.4832	'CLIFTON - CONCORDIA 115KV CKT 1'	
'BANNER_CO 345.00 - G1623&1629-T345.00 345KV CKT 1'	765	114.0115	'G16-110-TAP 345.00 - STEGALL 345KV CKT 1'	
'FT THOMPSON (FT2 KU1A) 345/230/13.8KV TRANSFORMER CKT 1'	313	107.4712	"P23:345:UMZW:# 705 #: FT2 IN SD. BREAKER FAULT (3396)"	
'FT THOMPSON (FT2 KU1B) 345/230/13.8KV TRANSFORMER CKT 1'	313	103.6825	"P43:345:UMZW:# 2419 #: FT2 IN SD. FT2 KU1B TRANSFORMER FAULT & FT2 2996 STUCK BKR"	
'GR ISLD-LNX3345.00 - GR ISLD3 345.00 345KV CKT Z'	720	124.1393	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
'HOSKINS (HOSKINS T2) 345/230/13.8KV TRANSFORMER CKT 1'	336	109.0027	"P42:345:NPPD:BKR-HOS-3312"	
'HOSKINS (HOSKN T4) 345/115/13.8KV TRANSFORMER CKT 1'	336	112.3116	"P42:345:NPPD:BKR-HOS-3310"	
'KELLY - KING HILL N.M. COOP (NEMAHA MARSHALL R.E.C. 115KV CKT 1'	92	135.9272	'CONCORDIA - ELM CREEK 230KV CKT 1'	
'KELLY - TECUMSEH HILL 161KV CKT 1'	112	122.9665	'CONCORDIA (CONCORD6) 230/115/13.8KV TRANSFORMER CKT 1'	
'MARSHAL3 115.00 - SMITTYVILLE N.M. COOP (NEMAHA MARSHALL R.E. 115KV CKT 1'	92	142.4537	'CLIFTON - CONCORDIA 115KV CKT 1'	
'MINGO - SETAB 345KV CKT 1'	762.5	108.8512	"P42:345:NPPD:BKR-AXT-3302"	

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
'KNOLL 230 - POSTROCK6 230.00 230KV CKT 1'	398	101.4931	System Intact	Advance Knoll - Post Rock 230kV ckt2.
'GERALD GENTLEMAN STATION - RED WILLOW 345KV CKT 1'	956	103.4719	'KEYSTONE - RED WILLOW 345KV CKT 1'	Rebuild GGS – Red Willow 345kV
'MINGO - RED WILLOW 345KV CKT 1'	785	117.5157	'POST ROCK - RED WILLOW 345KV CKT 1'	Rebuild Mingo – Red Willow 345kV

Additional NRIS thermal constraints were observed for single contingency (N-1), and multi-contingency (P1, P2, etc.) conditions. The table below summarizes constraints and associated mitigations.

Table 8-234 Group 9 Cluster NRIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
'COLUMEAST (COL.EAST T3) 230/115/13.8KV TRANSFORMER CKT 1'	187	117.8539	'COLUMEAST - SHELL CREEK 345KV CKT 1'	1. Add Grand Island – Seward county 345kV CKT 1 2. Add Grand Prairie – Hoskins 345kV CKT 1 3. Add Hoskins – Ft. Calhoun 345kV CKT 1
'DIXONCO 230.00 - TWIN CHURCH 230KV CKT 1'	320	115.6511	"P42:345:NPPD:BKR-HOS-3312"	
'FT RANDAL - FT THOMPSON 230KV CKT 1'	320	104.2082	'GRPRAR1-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1'	
FT RANDAL - LAKE PLATT 230KV CKT 1'	318.7	100.0769	'GRPRAR1-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1'	
'GR ISLD-LNX3345.00 - GR ISLD3 345.00 345KV CKT Z'	720	144.1995	'HOLT.CO3 345.00 - THEDFORD3 345.00 345KV CKT 1'	
'GR ISLD-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1'	720	143.1848	'HOLT.CO3 345.00 - THEDFORD3 345.00 345KV CKT 1'	
'GRAND ISLAND (GRAND.ISD T2) 230/115/13.8KV TRANSFORMER CKT 1'	316	100.8563	'GRAND ISLAND (GRAND.ISD T5) 230/115/13.8KV TRANSFORMER CKT 2'	
'GRAND ISLAND (GRAND.ISD T5) 230/115/13.8KV TRANSFORMER CKT 2'	316	100.7532	'GRAND ISLAND (GRAND.ISD T2) 230/115/13.8KV TRANSFORMER CKT 1'	

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
'GRPRAR1-LNX3345.00 - YANKTON 345KV CKT Z'	720	117.0697	"P45:345:UMZW:# 1327 #: FT2 IN SD."	
'SIOUX CITY - TWIN CHURCH 230KV CKT 1'	320	108.4544	'HOSKINS - RAUN 345KV CKT 1'	
'MONOLITH 7 115.00 - SHELDON 115KV CKT 1'	400	108.6878	'MONOLITH 3 345.00 - MOORE 345KV CKT 1'	Assume incremental upgrade of Monolith – Sheldon 345kV (NTC #200477; UID #71967)
'MULLERGREN - SOUTH HAYS 230KV CKT 1'	297	112.6202	'G13-010T 345.00 - SPEARVILLE 345KV CKT 1'	Rebuild Great Bend – South Hays 230kV CKT 1
'POST ROCK (POSTROCK T1) 345/230/13.8KV TRANSFORMER CKT 1'	600	108.6255	'G13-010T 345.00 - SPEARVILLE 345KV CKT 1'	Add Post Rock 345/230/13kV Transformer CKT 2

The tables below summarize constraints and associated mitigations assignable to incremental ERIS & NRIS steady state voltage. The steady state voltage constraints for mitigation are identified incremental to the thermal constraint mitigations.

Table 8-245 Group 9 Cluster ERIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
'103RD & ROKEBY 345KV'	0.94893	0.95	1.05	'G16-050-TAP 345.00 - POST ROCK 345KV CKT 1'	1. Add Grand Prairie - Antelope 345kV 2. Install +100 MVAR SVC at Keystone 345kV 3. Install 20.0MVAR Atwood Switch 115kV switched shunt capacitor 4. Install 10.0MVAR Heizer 69kV switched shunt capacitor 5. Install 50.0MVAR Mingo 115kV switched shunt capacitor 6. Install 30.0MVAR PH Run 115kV switched shunt capacitor
'ARNOLD 115KV'	0.895451	0.9	1.05	'COOPER - ST JOE 345KV CKT 1'	
'ATWOOD 115KV'	0.884642	0.9	1.05	'AXTELL - G16-050-TAP 345.00 345KV CKT 1'	
'ATWOOD SWITCH 115KV'	0.88895	0.9	1.05	'AXTELL - G16-050-TAP 345.00 345KV CKT 1'	
'AXTELL 345KV'	0.938944	0.95	1.05	'BASE CASE'	
'BEACH STATION 115KV'	0.89056	0.9	1.05	'COOPER - ST JOE 345KV CKT 1'	
'BEELER 115KV'	0.896827	0.9	1.05	'HOLCOMB - SETAB 345KV CKT 1'	
'BIRD CITY 115KV'	0.888941	0.9	1.05	'AXTELL - G16-050-TAP 345.00 345KV CKT 1'	
'BREWSTER 115KV'	0.897528	0.9	1.05	'AXTELL - G16-050-TAP 345.00 345KV CKT 1'	
'BUCKEYE_230 230.00 230KV'	0.898382	0.9	1.05	'G13-010T 345.00 - POST ROCK 345KV CKT 1'	
'BVERVLLY 115.00 115KV'	0.885973	0.9	1.05	'AXTELL - G16-050-TAP 345.00 345KV CKT 1'	
'CHASE 115KV'	0.897852	0.9	1.05	'G13-010T 345.00 - SPEARVILLE 345KV CKT 1'	
'CITY OF GOODLAND 115KV'	0.892007	0.9	1.05	'AXTELL - G16-050-TAP 345.00 345KV CKT 1'	

'CITY OF ST.FRANCIS 115KV'	0.891477	0.9	1.05	'AXTELL - G16-050-TAP 345.00 345KV CKT 1'	
'COLBY 115KV'	0.89721	0.9	1.05	'AXTELL - SWEETWATER 345KV CKT 1'	
'COLBY2 69KV'	0.896886	0.9	1.05	'BUCKNER7 345.00 - SPEARVILLE 345KV CKT 1'	
'COLUMWEST 230KV'	0.944429	0.95	1.05	'BASE CASE'	
'ELLIS 69KV'	0.893575	0.9	1.05	'AXTELL - SWEETWATER 345KV CKT 1'	
'FINNEY SWITCHING STATION 345KV'	0.947865	0.95	1.05	'BASE CASE'	
'FREMONT SUB F 69KV'	0.949353	0.95	1.05	'GEN647418 8-FREMONT 8'	
'G13_010_1 345.00 345KV'	0.888009	0.9	1.05	'G13-010T 345.00 - SPEARVILLE 345KV CKT 1'	
'G13-010T 345.00 345KV'	0.938241	0.95	1.05	'BASE CASE'	
'G15064_1 115.00 115KV'	0.89997	0.9	1.05	'COOPER - ST JOE 345KV CKT 1'	
'G15065_1 345.00 345KV'	0.898953	0.9	1.05	'COOPER - ST JOE 345KV CKT 1'	
'G16-050-TAP 345.00 345KV'	0.933068	0.95	1.05	'BASE CASE'	
'G16-096-TAP 345.00 345KV'	0.897054	0.9	1.05	'G15088_T 345.00 - MOORE 345KV CKT 1'	
'GEN-2016-050345.00 345KV'	0.866789	0.9	1.05	'G15088_T 345.00 - MOORE 345KV CKT 1'	
'GEN-2016-067345.00 345KV'	0.898953	0.9	1.05	'COOPER - ST JOE 345KV CKT 1'	
'GEN-2016-096345.00 345KV'	0.897054	0.9	1.05	'G15088_T 345.00 - MOORE 345KV CKT 1'	
'GOODLAND 115KV'	0.896535	0.9	1.05	'AXTELL - G16-050-TAP 345.00 345KV CKT 1'	
'GOODLAND TAP 115KV'	0.896585	0.9	1.05	'AXTELL - G16-050-TAP 345.00 345KV CKT 1'	
'GOVE 115KV'	0.89411	0.9	1.05	'AXTELL - SWEETWATER 345KV CKT 1'	
'GR ISLD3 345.00 345KV'	0.942015	0.95	1.05	'BASE CASE'	
'GR ISLD-LNX3345.00 345KV'	0.942015	0.95	1.05	'BASE CASE'	
'GRAHAM SUBSTATION 115KV'	0.887733	0.9	1.05	'COOPER - ST JOE 345KV CKT 1'	
'GRAND ISLAND 230KV'	0.937704	0.95	1.05	'BASE CASE'	
'GRINNELL 115KV'	0.892374	0.9	1.05	'AXTELL - G16-050-TAP 345.00 345KV CKT 1'	
'HERNDON 115KV'	0.89154	0.9	1.05	'AXTELL - G16-050-TAP 345.00 345KV CKT 1'	
'HOLCOMB 345KV'	0.948219	0.95	1.05	'BASE CASE'	

'HOXIE 115KV'	0.892391	0.9	1.05	'AXTELL - G16-050-TAP 345.00 345KV CKT 1'	
'HUMBOLDT 161KV'	0.940848	0.95	1.05	'COOPER - ST JOE 345KV CKT 1'	
'JOHNSON 115KV'	0.89526	0.9	1.05	'AXTELL - G16-050-TAP 345.00 345KV CKT 1'	
'KANARADO 115KV'	0.899327	0.9	1.05	'AXTELL - SWEETWATER 345KV CKT 1'	
'KNOLL 230 230KV'	0.895243	0.9	1.05	'G13-010T 345.00 - POST ROCK 345KV CKT 1'	
'LAWN RIDGE 115KV'	0.896575	0.9	1.05	'AXTELL - G16-050-TAP 345.00 345KV CKT 1'	
'LOCUST CREEK 161KV'	0.886932	0.9	1.05	'COOPER - ST JOE 345KV CKT 1'	
'LUDELL 3 115.00 115KV'	0.889367	0.9	1.05	'AXTELL - G16-050-TAP 345.00 345KV CKT 1'	
'LUDELLT3 115.00 115KV'	0.889373	0.9	1.05	'AXTELL - G16-050-TAP 345.00 345KV CKT 1'	
'MAGELLAN 69KV'	0.944064	0.95	1.05	'COOPER - ST JOE 345KV CKT 1'	
'MAGELLAN TAP 69KV'	0.944459	0.95	1.05	'COOPER - ST JOE 345KV CKT 1'	
'MCCOOL 345KV'	0.944056	0.95	1.05	'BASE CASE'	
'MCDONLD3 115.00 115KV'	0.886219	0.9	1.05	'AXTELL - G16-050-TAP 345.00 345KV CKT 1'	
'MINGO 115KV'	0.89997	0.9	1.05	'COOPER - ST JOE 345KV CKT 1'	
'MINGO 345KV'	0.923815	0.95	1.05	'BASE CASE'	
'MULLERGREN 230KV'	0.93294	0.95	1.05	'BASE CASE'	
'NATIONAL SUNFLOWER INDUSTRY TAP 115KV'	0.898166	0.9	1.05	'AXTELL - SWEETWATER 345KV CKT 1'	
'NESS CITY 115KV'	0.899604	0.9	1.05	'G15088_T 345.00 - MOORE 345KV CKT 1'	
'NORCATUR 115KV'	0.896434	0.9	1.05	'AXTELL - SWEETWATER 345KV CKT 1'	
'NORTH ATWOOD 115KV'	0.888808	0.9	1.05	'AXTELL - G16-050-TAP 345.00 345KV CKT 1'	
'NSI 115KV'	0.897575	0.9	1.05	'AXTELL - SWEETWATER 345KV CKT 1'	
'NW68TH & HOLDREGE 345KV'	0.943928	0.95	1.05	'G16-050-TAP 345.00 - POST ROCK 345KV CKT 1'	
'OBERLIN 115KV'	0.896254	0.9	1.05	'AXTELL - G16-050-TAP 345.00 345KV CKT 1'	
'OBERLIN TAP 115KV'	0.896468	0.9	1.05	'AXTELL - G16-050-TAP 345.00 345KV CKT 1'	
'ONEOK 3 115.00 115KV'	0.885813	0.9	1.05	'AXTELL - G16-050-TAP 345.00 345KV CKT 1'	
'PAULINE 345KV'	0.881442	0.9	1.05	'G15088_T 345.00 - MOORE 345KV CKT 1'	
'PHEASANT RUN 115KV'	0.89135	0.9	1.05	'AXTELL - G16-050-TAP 345.00 345KV CKT 1'	
'POST ROCK 345KV'	0.926569	0.95	1.05	'BASE CASE'	
'POSTROCK6 230.00 230KV'	0.935327	0.95	1.05	'BASE CASE'	

'PSCO LAMAR DC TIE 345KV'	0.884288	0.9	1.05	'BUCKNER7 345.00 - HOLCOMB 345KV CKT 1'	
'RANSOM 115KV'	0.897826	0.9	1.05	'COOPER - ST JOE 345KV CKT 1'	
'RANSOM 69KV'	0.898841	0.9	1.05	'BUCKNER7 345.00 - SPEARVILLE 345KV CKT 1'	
'RED WILLOW 345KV'	0.930555	0.95	1.05	'BASE CASE'	
'RHOADES 115KV'	0.887268	0.9	1.05	'COOPER - ST JOE 345KV CKT 1'	
'RIVERDALE 230KV'	0.935564	0.95	1.05	'BASE CASE'	
'RULETON 115KV'	0.897518	0.9	1.05	'AXTELL - SWEETWATER 345KV CKT 1'	
'S1398 5 161.00 161KV'	0.936027	0.95	1.05	'COOPER - ST JOE 345KV CKT 1'	
'S1399 5 161KV'	0.934626	0.95	1.05	'COOPER - ST JOE 345KV CKT 1'	
'SEGNTP 3 115.00 115KV'	0.895358	0.9	1.05	'AXTELL - G16-050-TAP 345.00 345KV CKT 1'	
'SEGUIN 3 115.00 115KV'	0.894148	0.9	1.05	'AXTELL - G16-050-TAP 345.00 345KV CKT 1'	
'SETAB 345KV'	0.936878	0.95	1.05	'BASE CASE'	
'SHARON SPRINGS 115KV'	0.897915	0.9	1.05	'G13-010T 345.00 - SPEARVILLE 345KV CKT 1'	
'SHELL CREEK 230KV'	0.947834	0.95	1.05	'BASE CASE'	
'SOUTH HAYS 230KV'	0.934464	0.95	1.05	'BASE CASE'	
'ST.FRANCIS 115KV'	0.890802	0.9	1.05	'AXTELL - G16-050-TAP 345.00 345KV CKT 1'	
'ST.FRANCIS TAP 115KV'	0.891605	0.9	1.05	'AXTELL - G16-050-TAP 345.00 345KV CKT 1'	
'SUB 1251 161KV'	0.992032	1.00186	1.0472	'ATCHSN 3 345.00 - COOPER 345KV CKT 1'	
'SUB 964 69KV'	0.948838	0.95	1.05	'G16-050-TAP 345.00 - POST ROCK 345KV CKT 1'	
'SUB 992 69KV'	0.94653	0.95	1.05	'GEN647418 8-FREMONT 8'	
'SUB 993 69KV'	0.937534	0.95	1.05	'COOPER - ST JOE 345KV CKT 1'	
'WALKEMEYER 7345.00 345KV'	0.94957	0.95	1.05	'BASE CASE'	
'WTCLF 3 115.00 115KV'	0.895026	0.9	1.05	'COOPER - ST JOE 345KV CKT 1'	
'WTCLFTP3 115.00 115KV'	0.89553	0.9	1.05	'COOPER - ST JOE 345KV CKT 1'	

Table 8-26 Group 9 Cluster NRIS Voltage Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
All NRIS voltage constraints are mitigated by ERIS assigned upgrades.				

CLUSTER GROUP 10 (SOUTHEAST OKLAHOMA/NORTHEAST TEXAS AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

No thermal or voltage constraints were observed in this group.

CLUSTER GROUP 12 (NORTHWEST ARKANSAS AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

No thermal or voltage constraints were observed in this group.

CLUSTER GROUP 13 (NORTHEAST KANSAS/NORTHWEST MISSOURI AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

One NRIS thermal constraint was observed for system-intact and single-contingency (N-1) conditions. The table below summarizes the constraint and associated mitigation.

Table 8-257 Group 13 Cluster NRIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
166TH STREET - JARBALO JUNCTION SWITCHING STATION 115KV CKT 1	239	112.40	P23:345:WERE:STRA_345-99::	Replace terminal equipment at Jarbalo Junction

The following requests will require an Affected System review from AECI:

GEN-2016_149
GEN-2016_150
GEN-2016_157
GEN-2016_158
GEN-2016_174
GEN-2016_176

CLUSTER GROUP 14 (SOUTH CENTRAL OKLAHOMA AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

Several ERIS thermal and voltage constraints were observed for system-intact and single-contingency (N-1) conditions. The table below summarizes constraints and associated mitigations.

Table 8-268 Group 14 Cluster ERIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
ARBUCKLE - G16-126-TAP 138.00 138KV CKT 1	191	165.53	BLUERIVER - PARK LANE 138KV CKT 1	Double Circuit from G16-126 Tap - Arbuckle 138kV
BLUERIVER - PARK LANE 138KV CKT 1	191	165.48	ARBUCKLE - G16-126-TAP 138.00 138KV CKT 1	

In addition to the ERIS constraint mitigations, several NRIS thermal and voltage constraints were observed for system-intact and single-contingency (N-1) conditions. The table below summarizes constraints and associated mitigations assignable to those requests that elect NRIS.

Table 8-279 Group 14 Cluster NRIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
ARBUCKLE - G16-126-TAP 138.00 138KV CKT 1	191	165.6	BLUERIVER - PARK LANE 138KV CKT 1	Double Circuit from G16-126 Tap - Arbuckle 138kV
BLUERIVER - PARK LANE 138KV CKT 1	191	165.42	ARBUCKLE - G16-126-TAP 138.00 138KV CKT 1	

CLUSTER GROUP 15 (EASTERN SOUTH DAKOTA)

In the event that the requested POI for GEN-2016-094 is not viable, this request may be incorporated into Group 15.

Generation in this area may require additional upgrades to relieve system reliability constraints related to NERC registered flowgate #6008. This flowgate requires additional review and updates resultant from the inclusion of the assigned network upgrades.

New requests for this study group as well as prior-queued requests are listed in Appendix C

Below is a list of the upgrades assigned, and the corresponding scenarios in which these upgrades were assigned. Scenario numbers are denoted as "S#".

Table 8-30 Group 15 Cluster Upgrade Scenarios

Scenario	Incremental Mitigation
0	None
2	Advance (R-Plan) Gerald Gentleman to Thedford to Holt 345kV circuit #1
	Addition of Antelope to Grand Prairie 345kV circuit #1
	Addition of GEN-2016-017 Tap to Ft. Thompson 345kV circuit #2
3	Rebuild GEN-2016-017 Tap to Ft. Thompson 345kV circuit #1
	Rebuild Ft. Thompson to Grand Prairie 345kV circuit #1
	Replace both Ft. Thompson 345/230kV transformers

Several ERIS non-converged constraints were observed for single contingency (N-1), and multi-contingency (P1, P2, etc.) conditions. The table below summarizes constraints and associated mitigations.

Table 8-31 Group 15 Cluster Non-Convergence ERIS Constraints

Monitored Elements	Mitigation
'ANTELOP-LNX3345.00 - GI1408_ABN 345.00 345KV CKT 1'	1. Build 2nd Circuit GEN-2016-017 Tap – Ft. Thompson 345kV 2. Build Grand Prairie – Antelope 345kV 3. Advance GGS - Thedford - Holt County 345 kV
'BRDLAND-LNX3345.00 - GI1408_ABN 345.00 345KV CKT 1'	
'BRDLAND-LNX3345.00 - HURON 345KV CKT Z'	
'BROADLAND - HURON 230KV CKT 1'	
'FT THOMPSON - FTTHOM1-LNX3345.00 345KV CKT Z'	

'FT THOMPSON - FTTHOM1-LNX3345.00 345KV CKT Z'	
'FTTHOM1-LNX3345.00 - G16-017-TAP 345.00 345KV CKT 1'	
'FTTHOM1-LNX3345.00 - G16-017-TAP 345.00 345KV CKT 1'	
'G16-017-TAP 345.00 - LELAND2-LNX3345.00 345KV CKT 1'	
'G1617TAP-LELANDOLDS-TLINE-REACTORS-CKT1'	
'GEN-2016-017TAP-FTTHOMPSONREACTOR-FTTHOMPSON-CKT1'	
'GEN-2016-017TAP-FTTHOMPSONREACTOR-FTTHOMPSON-CKT1'	
'GR ISLD-LNX3345.00 - GR ISLD3 345.00 345KV CKT Z'	
'GR ISLD-LNX3345.00 - GR ISLD3 345.00 345KV CKT Z'	
'GR ISLD-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1'	
'GR ISLD-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1'	
'GRANDPRAIRIE-HOLT-TLINE-REACTOR-CKT1'	
'GROTON - GROTON-LNX3 345.00 345KV CKT Z'	
'GROTON-LNX3 345.00 - LELAND1-LNX3345.00 345KV CKT 1'	
'GRPRAR1-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1'	
'GRPRAR1-LNX3345.00 - YANKTON 345KV CKT Z'	
'HURON (BD KU2A) 345/230/13.8KV TRANSFORMER CKT 1'	
'JUDSON 3345.00 - TANDE-LNX 345.00 345KV CKT 1'	
'JUDSON 3345.00 - TANDE-LNX 3345.00 345KV CKT 1'	
'LELAND OLDS - LELAND1-LNX3345.00 345KV CKT Z'	
'LELANDOLDS-GROTON-TLINE-REACTORS-345kV-CKT1'	

Table 8-32 Group 15 Cluster Non-Convergence NRIS Constraints

All non-converged constraints are mitigated by ERIS assigned upgrades.

Several ERIS thermal constraints were observed for single contingency (N-1), and multi-contingency (P1, P2, etc.) conditions. The table below summarizes constraints and associated mitigations.

Table 8-33 Group 15 Cluster ERIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
'DKSN_CO5 161.00 - LAKEFIELD 5 NO1 + NO 2 161KV CKT 1'	184	101.8885	"P13:115:UMZB:# 2729 #: WEL IN ND. WHEELOCK KV2A"	1. Rebuild GEN-2016-017 Tap – Ft. Thompson 345kV ckt1 2. Build GEN-2016-017 Tap – Ft. Thompson 345kV ckt2 3. Build Grand Prairie – Antelope 345kV ckt1 4. Advance GGS - Thedford - Holt County 345 kV 5. Rebuild Ft. Thompson – Grand Prairie 345kV
'FT THOMPSON - FTTHOM1-LNX3345.00 345KV CKT Z'	717	126.4141	'BRDLAND-LNX3345.00 - GI1408_ABN 345.00 345KV CKT 1'	
'FT THOMPSON - G16-094-TAP 230.00 230KV CKT 1'	352	113.1063	'FT THOMPSON - G16-094-TAP 230.00 230KV CKT 2'	
'FT THOMPSON - G16-094-TAP 230.00 230KV CKT 2'	352	113.1063	'FT THOMPSON - G16-094-TAP 230.00 230KV CKT 1'	
'FTTHOM1-LNX3345.00 - G16-017-TAP 345.00 345KV CKT 1'	717	126.2684	'BRDLAND-LNX3345.00 - GI1408_ABN 345.00 345KV CKT 1'	
'GR ISLD-LNX3345.00 - GR ISLD3 345.00 345KV CKT Z'	720	118.0381	'KELLY - MEADOWGROVE4230.00 230KV CKT 1'	
'GR ISLD-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1'	720	117.6454	'KELLY - MEADOWGROVE4230.00 230KV CKT 1'	
'FT THOMPSON (FT2 KU1A) 345/230/13.8KV TRANSFORMER CKT 1'	229.7682	720	"P23:345:UMZW:# 2423 #: GI IN NE. GI 1596 BKR FAULT"	Replace both Ft. Thompson 345/230kV transformers
'FT THOMPSON (FT2 KU1B) 345/230/13.8KV TRANSFORMER CKT 1'	229.794	720	"P23:345:UMZW:# 2422 #: GI IN NE. GI 1796 BKR FAULT"	
'GRPRAR1-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1'	720	103.8019	'ANTELOPE 3345.00 - YANKTON 345KV CKT 1'	Rating correction to 844 MVA
'GRPRAR1-LNX3345.00 - YANKTON 345KV CKT Z'	720	104.064	'ANTELOPE 3345.00 - YANKTON 345KV CKT 1'	

Table 8-284 Group 15 Cluster NRIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
'ABERDEEN SIEBRECHT - GROTON 115KV CKT 1'	129	118.9376	'G09_001IST 345.00 - WATERTOWN 345KV CKT 1'	1. Build 2nd circuit Aberdeen Siebrecht-Groton 115 kV 2. Build 2nd circuit BRISTOL - GROTON 115KV 3. Build 2nd circuit 'BRISTOL - SUMMIT 115KV 4. Build 2nd circuit G13_001IST 115.00 - SUMMIT 115KV 5. Build 2nd circuit G13_001IST 115.00 - WATERTOWN 115KV
'BRISTOL - GROTON 115KV CKT 1'	111	119.0426	'G09_001IST 345.00 - WATERTOWN 345KV CKT 1'	
'BRISTOL - SUMMIT 115KV CKT 1'	111	113.0546	'G09_001IST 345.00 - WATERTOWN 345KV CKT 1'	
'CRESTON - GROTON 115KV CKT 1'	200	132.1055	'G09_001IST 345.00 - WATERTOWN 345KV CKT 1'	
'G13_001IST 115.00 - SUMMIT 115KV CKT 1'	121	112.656	'G09_001IST 345.00 - WATERTOWN 345KV CKT 1'	
'G13_001IST 115.00 - WATERTOWN 115KV CKT 1'	121	126.5149	'G09_001IST 345.00 - WATERTOWN 345KV CKT 1'	
'GR ISLD-LNX3345.00 - GR ISLD3 345.00 345KV CKT Z'	720	123.6821	'ANTELOPE 3345.00 - YANKTON 345KV CKT 1'	Upgrade Holt County-Grand Island 345 kV line to 954 MVA and build 2nd circuit
'GR ISLD-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1'	720	122.684	'ANTELOPE 3345.00 - YANKTON 345KV CKT 1'	
'GRANITE FALLS - MN VALLEY TAP 230KV CKT 1'	259	101.1342	'GRANITE FALLS - MN VALLEY TAP 230KV CKT 1'	Rebuild 'GRANITE FALLS - MN VALLEY TAP 230KV CKT 1

Table 8-295 Group 15 Cluster ERIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
HOWARDCI-69kV'	0.813	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
SW173-69kV'	0.823	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
MOS-SPNC-69kV'	0.849	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
SW139-69kV'	0.850	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
MAD SE-69kV'	0.853	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	

MOS-LKV1-69kV'	0.858	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	1. Install 60.0MVAR Hanlon 230kV switched shunt capacitor. 2. Install 20.0MVAR Flandreau 115kV additional switched shunt capacitor.
LAMESA-69kV'	0.860	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
MOS-SALM-69kV'	0.861	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
MOS-MSTP-69kV'	0.862	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
WALLLK-69kV'	0.864	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
MARIONRD-69kV'	0.864	0.9	1.05	FTTHOM2-LNX3345.00 - GRPRAR2-LNX3 345KV CKT 1'	
HARTSE-69kV'	0.865	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
HARTFORD-69kV'	0.865	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
ELLIS SW-69kV'	0.866	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
MOS-MRRD-69kV'	0.870	0.9	1.05	FTTHOM2-LNX3345.00 - GRPRAR2-LNX3 345KV CKT 1'	
SW102-69kV'	0.870	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
SW159-69kV'	0.870	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
MOS-ELIS-69kV'	0.872	0.9	1.05	FTTHOM2-LNX3345.00 - GRPRAR2-LNX3 345KV CKT 1'	
MOS-WTWR-69kV'	0.874	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
SUNDOWN-69kV'	0.875	0.9	1.05	FTTHOM2-LNX3345.00 - GRPRAR2-LNX3 345KV CKT 1'	
SXFALLS-69kV'	0.876	0.9	1.05	FTTHOM2-LNX3345.00 - GRPRAR2-LNX3 345KV CKT 1'	
WILOWCRK-69kV'	0.876	0.9	1.05	FTTHOM2-LNX3345.00 - GRPRAR2-LNX3 345KV CKT 1'	
HANLON18 69kV'	0.878	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
DELAPRE-69kV'	0.879	0.9	1.05	FTTHOM2-LNX3345.00 - GRPRAR2-LNX3 345KV CKT 1'	
SW211-69kV'	0.880	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
SW1109-69kV'	0.881	0.9	1.05	FTTHOM2-LNX3345.00 - GRPRAR2-LNX3 345KV CKT 1'	
PUKWANA-69kV'	0.889	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
SW619-69kV'	0.890	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
HILLTOP-69kV'	0.891	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	

SW162-69kV'	0.891	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
MOS-PLAT-69kV'	0.892	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
MOS-HLTP-69kV'	0.892	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
SW145-69kV'	0.892	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
MOS-CLMN-69kV'	0.893	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
NWPS7632-69kV'	0.893	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
MOS-HMPA-69kV'	0.895	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
MOS-STRP-69kV'	0.898	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
MOS-RVR2-69kV'	0.898	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
MOS-RVR1-69kV'	0.898	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
MOS-P-T-69kV'	0.899	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
MOS-C-H-69kV'	0.899	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
MOS-CHNC-69kV'	0.899	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	
CHANCLRS-69kV'	0.899	0.9	1.05	'GRPRAR2-LNX3345.00 - YANKTON 345KV CKT Z'	

Table 8-36 Group 15 Cluster NRIS Voltage Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
All NRIS voltage constraints are mitigated by ERIS assigned upgrades.				

CLUSTER GROUP 16 (WESTERN NORTH DAKOTA)

New requests for this study group as well as prior-queued requests are listed in Appendix C

Below is a list of the upgrades assigned, and the corresponding scenarios in which these upgrades were assigned. Scenario numbers are denoted as "S#".

Table 8-37 Group 16 Cluster Upgrade Scenarios

Scenario	Incremental Mitigation
0	None
2	Addition new Emmons County 345kV substation along Antelope Valley Station to Broadland 345kV (500kV) and Fort Thompson to Leland Olds 345kV circuits
	Addition new McIntosh County 345kV substation along Groton to Leland Olds 345kV circuit #1
	Addition of a Emmons County to McIntosh County 345kV circuit
	Addition of a 2nd 345/230kV transformer at Tande station
3	Re-tap CTs along Antelope Valley Station to Broadland 345kV (500kV) to Huron 230kV circuit #1
	Replace Broadland 345/230kV transformer circuit #1
	Raise structures & re-tap CTs on Fort Thompson to Leland Olds 345kV circuit #1
	Convert Hilken 230kV substation to breaker and a half configuration
	Rebuild Neset to Tioga 230kV circuit #1

Several ERIS non-converged constraints were observed for single contingency (N-1), and multi-contingency (P1, P2, etc.) conditions. The table below summarizes constraints and associated mitigations.

Table 8-308 Group 16 Cluster Non-Convergence ERIS Constraints

Monitored Elements	Mitigation
'ANTELOP-LNX3345.00 - GI1408_ABN 345.00 345KV CKT 1'	1. Addition of a new Emmons County 345kV substation along Antelope Valley Station to Broadland 345kV (500kV) and Fort Thompson to Leland Olds 345kV circuits 2. Addition of a new McIntosh County 345kV substation along Groton to Leland Olds 345kV circuit 3. Addition of a new approximately 45 mile Emmons County to McIntosh County 345kV circuit
'BRDLAND-LNX3345.00 - GI1408_ABN 345.00 345KV CKT 1'	
'BRDLAND-LNX3345.00 - HURON 345KV CKT Z'	
'BROADLAND - HURON 230KV CKT 1'	
'FT THOMPSON - FTTHOM1-LNX3345.00 345KV CKT Z'	
'FT THOMPSON - FTTHOM1-LNX3345.00 345KV CKT Z'	
'FTTHOM1-LNX3345.00 - G16-017-TAP 345.00 345KV CKT 1'	
'FTTHOM1-LNX3345.00 - G16-017-TAP 345.00 345KV CKT 1'	
'G16-017-TAP 345.00 - LELAND2-LNX3345.00 345KV CKT 1'	
'G1617TAP-LELANDOLDS-TLINE-REACTORS-CKT1'	
'GEN-2016-017TAP-FTTHOMPSONREACTOR-FTTHOMPSON-CKT1'	
'GEN-2016-017TAP-FTTHOMPSONREACTOR-FTTHOMPSON-CKT1'	
'GR ISLD-LNX3345.00 - GR ISLD3 345.00 345KV CKT Z'	
'GR ISLD-LNX3345.00 - GR ISLD3 345.00 345KV CKT Z'	
'GR ISLD-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1'	
'GR ISLD-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1'	
'GRANDPRAIRIE-HOLT-TLINE-REACTOR-CKT1'	
'GROTON - GROTON-LNX3 345.00 345KV CKT Z'	
'GROTON-LNX3 345.00 - LELAND1-LNX3345.00 345KV CKT 1'	
'GRPRAR1-LNX3345.00 - HOLT.CO3 345.00 345KV CKT 1'	
'GRPRAR1-LNX3345.00 - YANKTON 345KV CKT Z'	
'HURON (BD KU2A) 345/230/13.8KV TRANSFORMER CKT 1'	
'LELAND OLDS - LELAND1-LNX3345.00 345KV CKT Z'	
'LELANDOLDS-GROTON-TLINE-REACTORS-345kV-CKT1'	
'JUDSON 3345.00 - TANDE-LNX 345.00 345KV CKT 1'	Addition of a 2nd 345/230kV transformer at Tande station
'JUDSON 3345.00 - TANDE-LNX 3345.00 345KV CKT 1'	

Table 8-39 Group 16 Cluster Non-Convergence NRIS Constraints

All non-converged constraints are mitigated by ERIS assigned upgrades.

Several ERIS thermal constraints were observed for single contingency (N-1), and multi-contingency (P1, P2, etc.) conditions. The table below summarizes constraints and associated mitigations.

Table 0-40 Group 16 Cluster ERIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
'ANTELOP-LNX3345.00 - AVSBRDTAP 345.00 345KV CKT 1'	478	172.3306	'LELAND2-LNX3345.00 - LLOFTTTAP 345.00 345KV CKT 1'	Re-tap CTs to achieve higher rating
'AVSBRDTAP 345.00 - BRDLAND-LNX3345.00 345KV CKT 1'	478	152.9036	'GEN-2016-017TAP-FTTHOMPSONREACTOR-FTTHOMPSON-CKT1'	Replace Broadland transformer
LELAND2-LNX3345.00 - LLOFTTTAP 345.00 345KV CKT 1'	717	114.3172	'ANTELOP-LNX3345.00 - AVSBRDTAP 345.00 345KV CKT 1'	Raise structures & re-tap CTs to achieve higher rating
BISMARK - HILKEN 4 230.00 230KV CKT 1'	351	121.9286	'GARRISON - JAMES TOWN 230KV CKT 1'	Convert Hilken to breaker and a half bay
BRDLAND-LNX3345.00 - HURON 345KV CKT Z'	478	152.4231	'GEN-2016-017TAP-FTTHOMPSONREACTOR-FTTHOMPSON-CKT1'	Re-Tap CTs to achieve higher rating
NESET 4 230.00 - TIOGA 230KV CKT Z'	506	109.8056	'JUDSON 3345.00 - TANDE-LNX 345.00 345KV CKT 1'	Replace 1 mile of conductor and jumpers

Additional NRIS thermal constraints were observed for single contingency (N-1), and multi-contingency (P1, P2, etc.) conditions. The table below summarizes constraints and associated mitigations.

Table 8-41 Group 16 Cluster NRIS Thermal Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
'BELFIELD - DICKINSON 230KV CKT 1'	263	108.2853	'BOWMAN 4 230.00 - RHAME 4 230.00 230KV CKT 1'	Updated rating sufficient for need.
'GROTON (GROTON KU2A) 345/115/13.8KV TRANSFORMER CKT 1'	257	105.2802	'G09_001IST 345.00 - WATERTOWN 345KV CKT 1'	Updated rating sufficient for need.

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
'J607 POI 230.00 - WISHEK 230KV CKT 1'	257	106.0654	'CENTER - JAMESTOWN 345KV CKT 1'	Not required unless it is identified as constraint in affected system study.
'KENMARE - STANLEY 115KV CKT 1'	61	113.8683	'NESET 7 115.00 - WHTEARTH-MW7115.00 115KV CKT 1'	Not required unless it is identified as constraint in affected system study.
'LELAND OLDS - STANTON 230KV CKT 1'	285.2	118.4344	'GEN615002 2-COAL CREEK'	Not required unless it is identified as constraint in affected system study.
'MCHENRY (230/115) 230/115/12.47KV TRANSFORMER CKT 1'	84	115.4273	'RUGBY - RUGBY OTP 115KV CKT 1'	Not required unless it is identified as constraint in affected system study.
'MERRCRT4 230.00 - WISHEK 230KV CKT 1'	257	104.8077	'CENTER - JAMESTOWN 345KV CKT 1'	Not required unless it is identified as constraint in affected system study.
'STANLEY - TIOGA 115KV CKT 1'	68	129.422	'NESET 7 115.00 - WHTEARTH-MW7115.00 115KV CKT 1'	Not required unless it is identified as constraint in affected system study.

Table 8-42 Group 16 Cluster ERIS Voltage Constraints

Monitored Element	TC Voltage (PU)	VMIN (PU)	VMAX (PU)	Contingency	Mitigation
AUSTIN 115kV'	0.871	0.9	1.05	NESET 7 115.00 WHTEARTH-MW7115.00 115KV CKT 1'	1. Install 60.0MVAR Hanlon 230kV switched shunt capacitor. 2. Install 20.0MVAR Flandreau 115kV additional switched shunt capacitor.
BELDEN 115kV'	0.871	0.9	1.05	NESET 7 115.00 WHTEARTH-MW7115.00 115KV CKT 1'	
BIGBEND 115kV'	0.88	0.9	1.05	NESET 7 115.00 WHTEARTH-MW7115.00 115KV CKT 1'	
BRDLAND3 345kV'	0.882	0.9	1.05	GROTON-LNX3 345.00 LLOGTNTAP 345.00 345KV CKT 1'	
BROOKBNK 115kV'	0.86	0.9	1.05	NESET 7 115.00 WHTEARTH-MW7115.00 115KV CKT 1'	
DELAPRE 69kV'	0.876	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
ELLIS SW 69kV'	0.861	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
ENEWTWN 115kV'	0.881	0.9	1.05	NESET 7 115.00 WHTEARTH-MW7115.00 115KV CKT 1'	
FINSTAD 115kV'	0.875	0.9	1.05	NESET 7 115.00 WHTEARTH-MW7115.00 115KV CKT 1'	
FTTHOMP3 345kV'	0.882	0.9	1.05	GROTON-LNX3 345.00 LLOGTNTAP 345.00 345KV CKT 1'	
G15_023_1 345kV'	0.882	0.9	1.05	GROTON-LNX3 345.00 LLOGTNTAP 345.00 345KV CKT 1'	
G16-017-TAP 345kV'	0.878	0.9	1.05	GROTON-LNX3 345.00 LLOGTNTAP 345.00 345KV CKT 1'	
GEN-2016-017345kV'	0.878	0.9	1.05	GROTON-LNX3 345.00 LLOGTNTAP 345.00 345KV CKT 1'	
GEN-2016-092345kV'	0.878	0.9	1.05	GROTON-LNX3 345.00 LLOGTNTAP 345.00 345KV CKT 1'	
GEN-2016-103345kV'	0.878	0.9	1.05	GROTON-LNX3 345.00 LLOGTNTAP 345.00 345KV CKT 1'	
GEN-2016-165345kV'	0.869	0.9	1.05	GROTON-LNX3 345.00 LLOGTNTAP 345.00 345KV CKT 1'	
GR PRAIRIE 3345kV'	0.869	0.9	1.05	GROTON-LNX3 345.00 LLOGTNTAP 345.00 345KV CKT 1'	
GR PRAIRIE3 345kV'	0.87	0.9	1.05	GROTON-LNX3 345.00 LLOGTNTAP 345.00 345KV CKT 1'	
HANLON18 69kV'	0.875	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
HARTFORD 69kV'	0.86	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
HARTSE 69kV'	0.859	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
HILLTOP 69kV'	0.889	0.9	1.05	GR ISLD-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
HOLT.CO3 345kV'	0.882	0.9	1.05	GROTON-LNX3 345.00 LLOGTNTAP 345.00 345KV CKT 1'	
HOWARDCI 69kV'	0.808	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
LAMESA 69kV'	0.854	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
LETCHER4 230kV'	0.897	0.9	1.05	GR ISLD-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
LLOGTNTAP 345kV'	0.948	0.95	1.05	'BASE CASE'	

LOSTWOOD 115kV'	0.884	0.9	1.05	NESET 7 115.00 WHTEARTH-MW7115.00 115KV CKT 1'	
MAD SE 69kV'	0.855	0.9	1.05	GRPRAR1-LNX3345.00 YANKTON 345KV CKT Z'	
MARIONRD 69kV'	0.861	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
MOE 115kV'	0.844	0.9	1.05	NESET 7 115.00 WHTEARTH-MW7115.00 115KV CKT 1'	
MOS-CLMN 69kV'	0.897	0.9	1.05	GRPRAR1-LNX3345.00 YANKTON 345KV CKT Z'	
MOS-ELIS 69kV'	0.869	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
MOS-GRNV 69kV'	0.89	0.9	1.05	G09_001IST 345.00 WATERTOWN 345KV CKT 1'	
MOS-HLTP 69kV'	0.89	0.9	1.05	GR ISLD-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
MOS-HMPA 69kV'	0.896	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
MOS-LKV1 69kV'	0.86	0.9	1.05	GRPRAR1-LNX3345.00 YANKTON 345KV CKT Z'	
MOS-MRRD 69kV'	0.867	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
MOS-MSTP 69kV'	0.856	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
MOS-PEEV 69kV'	0.89	0.9	1.05	G09_001IST 345.00 WATERTOWN 345KV CKT 1'	
MOS-PLAT 69kV'	0.89	0.9	1.05	GR ISLD-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
MOS-RVR1 69kV'	0.896	0.9	1.05	GR ISLD-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
MOS-RVR2 69kV'	0.896	0.9	1.05	GR ISLD-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
MOS-SALM 69kV'	0.858	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
MOS-SPNC 69kV'	0.845	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
MOS-WTWR 69kV'	0.876	0.9	1.05	GRPRAR1-LNX3345.00 YANKTON 345KV CKT Z'	
MTVERNS8 69kV'	0.895	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
OSBORN 115kV'	0.88	0.9	1.05	NESET 7 115.00 WHTEARTH-MW7115.00 115KV CKT 1'	
PALERMO 115kV'	0.895	0.9	1.05	NESET 7 115.00 WHTEARTH-MW7115.00 115KV CKT 1'	
PARSHALL 115kV'	0.895	0.9	1.05	NESET 7 115.00 WHTEARTH-MW7115.00 115KV CKT 1'	
PLANKCTY 69kV'	0.888	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
PSVSWTCH 115kV'	0.84	0.9	1.05	NESET 7 115.00 WHTEARTH-MW7115.00 115KV CKT 1'	
PUKWANA 69kV'	0.887	0.9	1.05	GR ISLD-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
PVALLEY 115kV'	0.84	0.9	1.05	NESET 7 115.00 WHTEARTH-MW7115.00 115KV CKT 1'	
RATLAKE 115kV'	0.851	0.9	1.05	NESET 7 115.00 WHTEARTH-MW7115.00 115KV CKT 1'	
RBNSNLAK 115kV'	0.869	0.9	1.05	NESET 7 115.00 WHTEARTH-MW7115.00 115KV CKT 1'	

ROSS 115kV'	0.853	0.9	1.05	NESET 7 115.00 WHTEARTH-MW7115.00 115KV CKT 1'	
ROSS 115kV'	0.853	0.9	1.05	NESET 7 115.00 WHTEARTH-MW7115.00 115KV CKT 1'	
ROSS 115kV'	0.882	0.9	1.05	PSVSWTCH-MW7115.00 WHTEARTH-MW7115.00 115KV CKT 1'	
ROSS 115kV'	0.882	0.9	1.05	PSVSWTCH-MW7115.00 WHTEARTH-MW7115.00 115KV CKT 1'	
STANLEY 115kV'	0.885	0.9	1.05	NESET 7 115.00 WHTEARTH-MW7115.00 115KV CKT 1'	
SUNDOWN 69kV'	0.872	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
SW102 69kV'	0.866	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
SW102 69kV'	0.866	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
SW1109 69kV'	0.878	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
SW145 69kV'	0.893	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
SW159 69kV'	0.867	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
SW162 69kV'	0.892	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
SW173 69kV'	0.818	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
SW211 69kV'	0.883	0.9	1.05	GRPRAR1-LNX3345.00 YANKTON 345KV CKT Z'	
SW409 69kV'	0.891	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
SW619 69kV'	0.888	0.9	1.05	GR ISLD-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
SW752 69kV'	0.88	0.9	1.05	G09_001IST 345.00 WATERTOWN 345KV CKT 1'	
SXFALLS 69kV'	0.873	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
VANHOOK 115kV'	0.887	0.9	1.05	NESET 7 115.00 WHTEARTH-MW7115.00 115KV CKT 1'	
WALLLK 69kV'	0.858	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	
WHTEARTH 115kV'	0.839	0.9	1.05	NESET 7 115.00 WHTEARTH-MW7115.00 115KV CKT 1'	
WILMOT 69kV'	0.898	0.9	1.05	G09_001IST 345.00 WATERTOWN 345KV CKT 1'	
WILOWCRK 69kV'	0.873	0.9	1.05	GRPRAR1-LNX3345.00 HOLT.CO3 345.00 345KV CKT 1'	

Table 8-43 Group 16 Cluster NRIS Voltage Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
All NRIS voltage constraints are mitigated by ERIS assigned upgrades.				

Table 8-44 Group 16 Cluster NRIS Voltage Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
None meeting mitigation criteria				

CLUSTER GROUP 17 (WESTERN SOUTH DAKOTA)

The requested POI for GEN-2016-094 may not be viable, additional analysis will be required to identify if additional mitigation is required with a POI at Ft. Thompson. The interconnection cost estimate is for a POI at Ft. Thompson. In the event that the requested POI for GEN-2016-094 is not viable, this request may be incorporated into Group 15.

New requests for this study group as well as prior-queued requests are listed in Appendix C.

Table 8-45 Group 17 Cluster ERIS Constraints

Monitored Element	Limiting Rate A/B (MVA)	TC %Loading (%MVA)	Contingency	Mitigation
'FT THOMPSON - G16-094-TAP 230.00 230KV CKT 1'	352	113.1063	'FT THOMPSON - G16-094-TAP 230.00 230KV CKT 2'	Upgrade terminal equipment at Ft. Thompson 230kV
'FT THOMPSON - G16-094-TAP 230.00 230KV CKT 2'	352	113.0186	'FT THOMPSON - G16-094-TAP 230.00 230KV CKT 1'	

CLUSTER GROUP 18 (EASTERN NORTH DAKOTA)

No additional generation was studied for this group.

8.2 LIMITED OPERATION

Limited Operation results are listed below. While these results are based on the criteria listed in GIP 8.4.3, the Interconnection Customer may request additional scenarios for Limited Operation based on higher-queued Interconnection Requests not being placed in service. Requests not being placed in service. Please refer to section 8 for power flow constraint mitigation.

Table 8-46: Limited Operation Results

Group Number	Request	Available MW Before Mitigation	Most-Limiting Constraint
Group1	GEN-2016-118	ERIS - 271.90	DOVER SW - HENESSEY 138KV CKT 1
		NRIS - 180.65	TUPELO - TUPELO TAP 138KV CKT 1

	GEN-2016-131	ERIS – 2.5 MW	No ERIS Results for mitigation
		NRIS - 0	CIMARRON (CIMARON1) 345/138/13.8KV TRANSFORMER CKT 1
Group 2	ASGI-2016-010	ERIS – 48.72	CAPROCK REC-PEMBROOK () 115/69/13.2KV TRANSFORMER CKT 1
	GEN-2016-161	ERIS – 0	MARTIN SUB - PANTEX NORTH SUB 115KV CKT 1
Group 4	GEN-2016-111	ERIS – 226.24	RENO COUNTY (RENO TX-2) 345/115/14.4KV TRANSFORMER CKT 1
		NRIS - 209.89	RENO COUNTY (RENO TX-2) 345/115/14.4KV TRANSFORMER CKT 1
	GEN-2016-112	ERIS - 164.81	RENO COUNTY (RENO TX-2) 345/115/14.4KV TRANSFORMER CKT 1
		NRIS - 152.90	RENO COUNTY (RENO TX-2) 345/115/14.4KV TRANSFORMER CKT 1
	GEN-2016-113	ERIS - 116.11	RENO COUNTY (RENO TX-2) 345/115/14.4KV TRANSFORMER CKT 1
		NRIS - 107.73	RENO COUNTY (RENO TX-2) 345/115/14.4KV TRANSFORMER CKT 1
	GEN-2016-114	ERIS – 232.23	RENO COUNTY (RENO TX-2) 345/115/14.4KV TRANSFORMER CKT 1
		NRIS - 215.46	RENO COUNTY (RENO TX-2) 345/115/14.4KV TRANSFORMER CKT 1
	GEN-2016-122	ERIS - 168.55	RENO COUNTY (RENO TX-2) 345/115/14.4KV TRANSFORMER CKT 1
		NRIS - 156.38	RENO COUNTY (RENO TX-2) 345/115/14.4KV TRANSFORMER CKT 1
	GEN-2016-160	ERIS – 19.8	No ERIS Results for mitigation
		NRIS – 19.8	No NRIS Results for mitigation
Group 6	ASGI-2016-009	ERIS – 0	System Intact
	GEN-2015-039	ERIS – 0	System Intact
		NRIS-ERIS Limited	System Intact
	GEN-2015-040	ERIS – 0	System Intact
		NRIS-ERIS Limited	System Intact
	GEN-2015-078	ERIS – 0	System Intact
		NRIS-ERIS Limited	System Intact
	GEN-2016-039	ERIS – 0	System Intact
	GEN-2015-099	ERIS – 0	System Intact
	GEN-2016-077	ERIS – 0	System Intact
		NRIS-ERIS Limited	System Intact
	GEN-2016-078	ERIS – 0	System Intact
		NRIS-ERIS Limited	System Intact
	GEN-2016-120	ERIS – 0	System Intact
		NRIS-ERIS Limited	System Intact
	GEN-2016-121	ERIS – 0	System Intact
		NRIS-ERIS Limited	System Intact
	GEN-2016-123	ERIS – 0	System Intact
		NRIS-ERIS Limited	System Intact
	GEN-2016-124	ERIS – 0	System Intact
		NRIS-ERIS Limited	System Intact
	GEN-2016-125	ERIS – 0	System Intact
		NRIS-ERIS Limited	System Intact
	GEN-2016-169	ERIS – 0	System Intact
		NRIS-ERIS Limited	System Intact
	GEN-2016-171	ERIS – 0	System Intact
		NRIS-ERIS Limited	System Intact

	GEN-2016-172	ERIS – 0	System Intact
		NRIS-ERIS Limited	System Intact
	GEN-2016-175	ERIS – 0	System Intact
		NRIS-ERIS Limited	System Intact
	GEN-2016-177	ERIS – 0	'National Enrichment Plant Sub - TARGA 3115.00 115KV CKT 1'
Group 7	GEN-2016-091	ERIS – 303.6	No ERIS Results for mitigation
	GEN-2016-095	ERIS - 200	No ERIS Results for mitigation
		NRIS - 200	No NRIS Results for mitigation
	GEN-2016-097	ERIS – 62.91	'CORNVILLE - NORGE ROAD 138KV CKT 1'
		NRIS-ERIS Limited	
	GEN-2016-132	ERIS – 6.12	No ERIS Results for mitigation
		NRIS – 6.12	No NRIS Results for mitigation
Group 8	GEN-2016-024	ERIS – 0	LACYGNE - WAVERLY7 345.00 345KV CKT 1
		NRIS-ERIS Limited	
	GEN-2016-072	ERIS – 0	G15063_T 345.00 - MATHWSN7 345.00 345KV CKT 1
		NRIS-ERIS Limited	
	GEN-2016-100	ERIS – 0	G16-100-TAP 345.00 - SPRING CREEK 345KV CKT 1
		NRIS-ERIS Limited	
	GEN-2016-101	ERIS – 0	G16-100-TAP 345.00 - SPRING CREEK 345KV CKT 1
		NRIS-ERIS Limited	
	GEN-2016-119	ERIS – 0	G16-100-TAP 345.00 - SPRING CREEK 345KV CKT 1
		NRIS-ERIS Limited	
	GEN-2016-127	ERIS – 0	DOMES - MOUND ROAD 138KV CKT 1
		NRIS-ERIS Limited	
	GEN-2016-128	ERIS - 0	G15063_T 345.00 - MATHWSN7 345.00 345KV CKT 1
		NRIS-ERIS Limited	
	GEN-2016-133	ERIS – 0	GRDA1 - GREC TAP5 345.00 345KV CKT 1
		NRIS-ERIS Limited	
	GEN-2016-134	ERIS – 0	GRDA1 - GREC TAP5 345.00 345KV CKT 1
		NRIS-ERIS Limited	
	GEN-2016-135	ERIS – 0	GRDA1 - GREC TAP5 345.00 345KV CKT 1
		NRIS-ERIS Limited	
	GEN-2016-136	ERIS – 0	GRDA1 - GREC TAP5 345.00 345KV CKT 1
		NRIS-ERIS Limited	
	GEN-2016-137	ERIS – 0	GRDA1 - GREC TAP5 345.00 345KV CKT 1
		NRIS-ERIS Limited	
	GEN-2016-138	ERIS – 0	GRDA1 - GREC TAP5 345.00 345KV CKT 1
		NRIS-ERIS Limited	
	GEN-2016-139	ERIS – 0	GRDA1 - GREC TAP5 345.00 345KV CKT 1
		NRIS-ERIS Limited	
	GEN-2016-140	ERIS – 0	GRDA1 - GREC TAP5 345.00 345KV CKT 1
		NRIS-ERIS Limited	
	GEN-2016-141	ERIS – 0	GRDA1 - GREC TAP5 345.00 345KV CKT 1
		NRIS-ERIS Limited	
	GEN-2016-142	ERIS – 0	GRDA1 - GREC TAP5 345.00 345KV CKT 1
		NRIS-ERIS Limited	
	GEN-2016-143	ERIS – 0	GRDA1 - GREC TAP5 345.00 345KV CKT 1
		NRIS-ERIS Limited	
	GEN-2016-144	ERIS – 0	GRDA1 - GREC TAP5 345.00 345KV CKT 1
		NRIS-ERIS Limited	
	GEN-2016-145	ERIS – 0	GRDA1 - GREC TAP5 345.00 345KV CKT 1
		NRIS-ERIS Limited	
	GEN-2016-146	ERIS – 0	GRDA1 - GREC TAP5 345.00 345KV CKT 1
		NRIS-ERIS Limited	
	GEN-2016-148	ERIS – 0	BARTLESVILLE COMANCHE - MOUND ROAD 138KV CKT 1
		NRIS-ERIS Limited	

	GEN-2016-153	ERIS – 0	G15063_T 345.00 - MATHWSN7 345.00 345KV CKT 1
		NRIS-ERIS Limited	
	GEN-2016-162	ERIS – 0	LACYGNE - WAVERLY7 345.00 345KV CKT 1
		NRIS-ERIS Limited	
	GEN-2016-163	ERIS – 0	LACYGNE - WAVERLY7 345.00 345KV CKT 1
		NRIS-ERIS Limited	
	GEN-2016-173	ERIS – 0	LACYGNE - WAVERLY7 345.00 345KV CKT 1
		NRIS-ERIS Limited	
Group 9	GEN-2016-034	ERIS – 0	'MINGO - RED WILLOW 345KV CKT 1'
	GEN-2016-074	ERIS – 0	'MINGO - RED WILLOW 345KV CKT 1'
		NRIS – ERIS Limited	
	GEN-2016-096	ERIS – 0	'MINGO - RED WILLOW 345KV CKT 1'
	GEN-2016-106	ERIS – 0	'MINGO - RED WILLOW 345KV CKT 1'
		NRIS – ERIS Limited	
	GEN-2016-110	ERIS – 0	'MINGO - RED WILLOW 345KV CKT 1'
		NRIS – ERIS Limited	
	GEN-2016-147	ERIS – 0	'MINGO - RED WILLOW 345KV CKT 1'
		NRIS – ERIS Limited	
	GEN-2016-159	ERIS – 0	'HOSKINS (HOSKN T4) 345/115/13.8KV TRANSFORMER CKT 1'
		NRIS – ERIS Limited	
	GEN-2016-165	ERIS – 0	'GR ISLD-LNX3345.00 - GR ISLD3 345.00 345KV CKT Z'
		NRIS – ERIS Limited	
Group 10	GEN-2016-167	ERIS – 73.5	No ERIS Results for mitigation
		NRIS – 73.5	No NRIS Results for mitigation
Group 12	GEN-2016-166	ERIS - 35	No ERIS Results for mitigation
		NRIS - 35	No NRIS Results for mitigation
Group 13	GEN-2016-088	ERIS – 151.2	No NRIS Results for mitigation
		NRIS – 151.2	No NRIS Results for mitigation
	GEN-2016-115	ERIS – 300	No NRIS Results for mitigation
		NRIS – 300	No NRIS Results for mitigation
	GEN-2016-149	ERIS – 302	No ERIS Results for mitigation
		NRIS – 222.6	166TH STREET - JARBALO JUNCTION SWITCHING STATION 115KV CKT 1
	GEN-2016-150	ERIS -302	No ERIS Results for mitigation
		NRIS – 222.6	166TH STREET - JARBALO JUNCTION SWITCHING STATION 115KV CKT 1
	GEN-2016-157	ERIS – 252	No NRIS Results for mitigation
		NRIS – 252	No NRIS Results for mitigation
	GEN-2016-158	ERIS – 252	No NRIS Results for mitigation
		NRIS – 252	No NRIS Results for mitigation
	GEN-2016-168	ERIS – 20	No NRIS Results for mitigation
		NRIS – 20	No NRIS Results for mitigation
	GEN-2016-174	ERIS -302	No ERIS Results for mitigation
		NRIS – 222.6	166TH STREET - JARBALO JUNCTION SWITCHING STATION 115KV CKT 1
	GEN-2016-176	ERIS -302	No ERIS Results for mitigation
		NRIS – 222.6	166TH STREET - JARBALO JUNCTION SWITCHING STATION 115KV CKT 1
Group 14	GEN-2016-102	ERIS – 92.49	ARBUCKLE - G16-126-TAP 138.00 138KV CKT 1
		NRIS – 92.43	ARBUCKLE - G16-126-TAP 138.00 138KV CKT 1
	GEN-2016-126	ERIS – 105.74	ARBUCKLE - G16-126-TAP 138.00 138KV CKT 1
		NRIS – 105.66	ARBUCKLE - G16-126-TAP 138.00 138KV CKT 1
	GEN-2016-129	ERIS - 132	No ERIS Results for mitigation
		NRIS - 132	No NRIS Results for mitigation

Group 15	GEN-2016-036	ERIS – 0	'SPLIT ROCK - WHITE 345KV CKT 1'
	GEN-2016-087	ERIS – 0	'SPLIT ROCK - WHITE 345KV CKT 1'
	GEN-2016-092	ERIS – 0	'SPLIT ROCK - WHITE 345KV CKT 1'
		NRIS – ERIS Limited	
	GEN-2016-103	ERIS – 0	'SPLIT ROCK - WHITE 345KV CKT 1'
		NRIS – ERIS Limited	
	GEN-2016-164	ERIS – 0	'SPLIT ROCK - WHITE 345KV CKT 1'
		NRIS – ERIS Limited	
Group 16	GEN-2016-108	ERIS – 0	'BRDLAND-LNX3345.00 - HURON 345KV CKT Z'
		NRIS – ERIS Limited	
	GEN-2016-130	ERIS – 0	'MERRCRT4 230.00 - WISHEK 230KV CKT 1'
		NRIS – ERIS Limited	
	GEN-2016-151	ERIS – 0	'MERRCRT4 230.00 - WISHEK 230KV CKT 1'
		NRIS – ERIS Limited	
	GEN-2016-152	ERIS – 0	'MERRCRT4 230.00 - WISHEK 230KV CKT 1'
		NRIS – ERIS Limited	
	GEN-2016-155	ERIS – 0	'BISMARK - HILKEN 4 230.00 230KV CKT 1'
		NRIS – ERIS Limited	
Group 17	GEN-2016-094	ERIS – 129.9	FT THOMPSON - G16-094-TAP 230.00 230KV CKT 1
		NRIS-ERIS Limited	

8.3 CURTAILMENT AND SYSTEM RELIABILITY

In no way does this study guarantee operation for all periods of time. It should be noted that although this study analyzed many of the most probable contingencies, it is not an all-inclusive list and cannot account for every operational situation. Because of this, it is likely that the Customer(s) may be required to reduce their generation output to 0 MW, also known as curtailment, under certain system conditions to allow system operators to maintain the reliability of the transmission network.

9 STABILITY & SHORT CIRCUIT ANALYSIS

A stability and short-circuit analysis was conducted for each Interconnection Request using modified versions of the MDWG Models dynamic cases. The stability analysis assumes that all upgrades identified in the power flow analysis are in-service unless otherwise noted in the individual group stability study.

For each group, the interconnection requests are studied at 100% nameplate output while the other groups are dispatched at 20% output for Variable Energy Resource (VER) requests and 100% output for other requests. The output of the Interconnection Customer's facility is offset in each model by a reduction in output of existing online SPP generation.

A synopsis is included for each group. The detailed stability study for each group can be found in the Appendices.

A preliminary short-circuit analysis was performed for this study and will be refined in the Interconnection Facilities Study with any additional required upgrades and cost assignment identified at that time.

9.1 POWER FACTOR REQUIREMENTS SUMMARY

Power factor requirements will be in accordance with FERC Order No. 827, Final Rule, Issued June 16, 2016.

9.2 CLUSTER STABILITY AND SHORT-CIRCUIT SUMMARY

CLUSTER GROUP 1 (WOODWARD AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

The Group 1 stability analysis for this area was performed by S&C Electric (S&C). With the new requests modeled, violations of stability damping criteria and voltage recovery criteria were observed.

The consultant observed that certain prior outage contingencies require curtailment of study generation as a system adjustment.

With all previously-assigned and currently-assigned Network Upgrades placed in service and identified system adjustments applied, no violations were observed, including violations of low-voltage ride-through requirements, for the probable contingencies studied.

CLUSTER GROUP 2 (HITCHLAND AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

The Group 2 stability analysis for this area was performed by Quanta Technology (Quanta). With the new requests modeled, violations of stability damping criteria and voltage recovery criteria were observed. Upgrades identified in the power flow analysis were also tested in the stability analysis.

The consultant has identified some reactor banks on the 345kV system with proximity to the Woodward EHV station may need to be switched out of service under system conditions of high wind generation in the Hitchland area. Reactors located on the following facilities were initialized to 0 Mvar:

- Beaver County - Badger 345kV
- Woodward - GEN-2016-003-Tap 345kV
- Woodward 345kV (located on Transformer Tertiaries)
- Woodward - Thistle 345kV
- Thistle - GEN-2016-005-Tap 345kV
- Buffalo - Thistle 345kV
- Buffalo - Wichita 345kV

With all previously-assigned and currently-assigned Network Upgrades placed in service and identified system adjustments applied, no violations were observed, including violations of low-voltage ride-through requirements, for the probable contingencies studied.

CLUSTER GROUP 3 (SPEARVILLE AREA)

No new interconnection requests in this group.

CLUSTER GROUP 4 (NORTHWEST KANSAS AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

The Group 4 stability analysis for this area was performed by POWER-tek Global Inc. (POWER-tek). With the new requests modeled, violations of stability damping criteria and voltage recovery criteria were not observed.

There were no impacts on the stability performance of the SPP system.

With all previously-assigned and currently-assigned Network Upgrades placed in service, no violations were observed, including violations of low-voltage ride-through requirements, for the probable contingencies studied.

CLUSTER GROUP 6 (SOUTH TEXAS PANHANDLE/NEW MEXICO AREA)

The requested POI for GEN-2016-077 is not viable, additional analysis will be required to identify if additional mitigation is required with a viable POI on the requested circuit. The interconnection cost estimate is for a valid POI on the requested circuit.

New requests for this study group as well as prior-queued requests are listed in Appendix C.

The Group 6 cases included the following system adjustments of dispatching, to maximum output, generation interconnected at the same or adjacent substations to a current study request:

- Mustang units: GEN-2015-040 & GEN-2015-078
- TUCO units: GEN-2016-120 & GEN-2016-175
- Tolk units: GEN-2016-123, GEN-2016-124, & GEN-2016-125
- Hobbs & Gaines units: GEN-2016-169 & GEN-2016-171
- Plant X units: GEN-2015-039 & GEN-2016-172

The Group 6 stability analysis for this area was performed by Mitsubishi Electric Power Products (MEPPI). With the new requests modeled, voltage instability, violations of voltage recovery criteria, and generation tripping off were observed. Upgrades identified in the power flow analysis were also tested in the stability analysis.

To mitigate the voltage instability, violations of voltage recovery criteria, and generation tripping off the following upgrades were implemented in each season:

- Crawfish Draw +600 MVAR SVC injection at the 765 kV bus
- Crawfish Draw 345/230 kV autotransformer #2
- Crawfish Draw – Crossroads 765 kV circuit #1
- Crawfish Draw – Midpoint Substation – Seminole (OKGE) 765 kV circuit #1 & #2
    - Due to reactive power demand from line loadings, in-line reactors were switched off
- Crossroads 765/345 kV transformer #1 and #2
- Crawfish Draw 765/345 kV transformer #1 and #2
- Seminole 765/345 kV transformer #1 and #2
- Hobbs to Yoakum to Tuco 345 kV circuit #1 (advancement in 17W and 18S)
- Yoakum 345/230 kV transformer #1 (advancement in 17W and 18S)
- Tolk 345/230 kV transformer #3

During the analysis it was determined that the addition of a substation tying both 765 kV circuits together at approximately 50% of the line length reduced the severity of a single circuit outage and resulted in significant reduction in the dynamic reactive equipment required to maintain system stability for outages in the Crawfish Draw/Seminole region.

SPP determined the 765 kV Network Upgrade cost estimates using conceptual amounts which require a facility study to substantiate.

Prior to completion of Facility Study, the GEN-2016-077 & GEN-2016-078 customers must provide SPP with an updated model or fault simulation instructions from the inverter vendor that mitigates the simulation tripping identified.

The consultant also noted that for certain prior outage conditions curtailment (system adjustment) will be needed to maintain system stability for subsequent circuit outages.

With all previously-assigned and currently-assigned Network Upgrades placed in service and identified system adjustments applied, no violations were observed (except as noted earlier), including violations of low-voltage ride-through requirements, for the probable contingencies studied.

CLUSTER GROUP 7 (SOUTHWESTERN OKLAHOMA AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

The Group 7 cases included the following system adjustments of dispatching, to maximum output, generation interconnected at the same or adjacent substations to a current study request:

- Southwestern Station & Anadarko units: GEN-2016-097

The Group 7 stability analysis for this area was performed by S&C Electric Company (S&C). With the new requests modeled system instability was observed.

The consultant noted that for certain faults, the generating facility comprised of the higher queued requests GEN-2003-004, GEN-2004-023, & GEN-2005-003 exhibited a simulation numerical issue; the GNET command was implemented for that facility. Additionally, abnormal oscillations were observed for a prior outage condition which was not improved through curtailment of current study generation. The system adjustment necessary to remedy the observed oscillations may involve curtailment of other generating units which requires analysis beyond the scope of this study.

With all previously-assigned and currently-assigned Network Upgrades placed in service and identified system adjustments applied, no violations were observed (except as noted earlier), including violations of low-voltage ride-through requirements, for the probable contingencies studied.

CLUSTER GROUP 8 (NORTH OKLAHOMA/SOUTH CENTRAL KANSAS AREA)

Complete results for requests in this cluster group including the transmission reinforcement upgrades identified during the evaluation of the Gerald Gentleman Station registered NERC flowgate #6006, refined upgrades to address stuck breaker conditions, and curtailment for prior outage conditions will be provided in a later update.

New requests for this study group as well as prior-queued requests are listed in Appendix C.

The Group 8 cases included the following system adjustments of dispatching, to maximum output, generation interconnected at the same or adjacent substations to a current study request:

- Sooner & Spring Creek units: GEN-2016-100, GEN-2016-101, GEN-2016-119, & GEN-2016-128
- West Pawhuska unit: GEN-2016-127 & GEN-2016-148
- Northeastern units & GRDA Energy Center: GEN-2016-133 – GEN-2016-146

The Group 8 stability analysis for this area was performed by Mitsubishi Electric Power Products (MEPPI). With the new requests modeled, voltage instability, violations of voltage recovery criteria, and generation tripping off were observed. Upgrades identified in the power flow analysis were also tested in the stability analysis.

To mitigate the voltage instability, violations of voltage recovery criteria, and generation tripping off the following upgrades were implemented in each season:

- Redington to Woodring 345 kV circuit #2
- Hunter to Woodring 345 kV circuit #2
- Redington to Spring Creek 345 kV circuit #1
- Tulsa North 345/138 kV transformer #2
- Static Var Compensators (SVC)
    - +300 Mvar SVC at Tulsa North 345 kV bus (wind plant side of 765 kV line)
    - +300 Mvar SVC at Tulsa North 345 kV bus (transmission side of 765 kV line)

MEPPI noted that the SVC solutions at the Tulsa North 345kV bus mitigated a portion of the contingencies around the substation. For a few contingencies a reasonable solution was not determined due to the 2500MW of generation interconnected at the Tulsa North 345kV substation being through 360 miles of 765kV transmission line. For certain contingencies the long transmission line caused GEN-2016-133 through GEN-2016-146 to trip offline due to overvoltage protection. With overvoltage protection disabled these projects remained online. Prior to completion of Facility Study these interconnection customers must provide SPP a modified project design that will meet the voltage ride through requirements of FERC Order #661A.

Prior to completion of Facility Study, the GEN-2016-173 customer must provide SPP with an updated model or fault simulation instructions from the inverter vendor that mitigates the simulation tripping identified.

The consultant also noted that for certain prior outage conditions curtailment (system adjustment) will be needed to maintain stability for subsequent outages.

With all previously-assigned and currently-assigned Network Upgrades placed in service and identified system adjustments applied, no violations were observed (except as noted earlier), including violations of low-voltage ride-through requirements, for the probable contingencies studied.

CLUSTER GROUP 9 (NEBRASKA AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

Generation in this area may require additional upgrades to relieve system reliability constraints related to NERC registered flowgates #5221, #6006, #6007, & #6008. These flowgates require additional review and updates resultant from the inclusion of the assigned network upgrades.

The Group 9 cases included the following system adjustments of dispatching, to maximum output, generation interconnected at the same or adjacent substations to a current study request:

- Laramie River Station units: GEN-2016-034 & GEN-2016-110
- Sheldon units: GEN-2016-096
- Gerald Gentleman Station units: GEN-2016-074 & GEN-2016-106
- Neal units: GEN-2016-059

The Group 9 stability analysis for this area was performed by Mitsubishi Electric Power Products (MEPPI). With the new requests modeled, violations of stability damping criteria and voltage recovery criteria were observed. Upgrades identified in the power flow analysis were also tested in the stability analysis.

To mitigate the voltage instability, violations of voltage recovery criteria, and generation tripping off the following upgrades were implemented in each season:

- Addition of Keystone to Red Willow 345kV circuit #1
- Addition of Post Rock to Red Willow 345kV circuit #1
- Addition of Antelope to Grand Prairie 345kV circuit #1
- Reroute Laramie River Station (GEN-2016-110-Tap) to Stegall 345kV circuit #1 through the GEN-2016-023-Tap substation
- Addition of SVC with +100MVAR injection at Keystone 345kV

It should be noted that for certain prior outage conditions curtailment (system adjustment) will be needed to maintain system stability for subsequent circuit outages.

The High GGS Scenario Stability Analysis determined that with the mitigations applied from the normal dispatch scenario no violations of stability damping criteria and voltage recovery criteria were observed. With all previously-assigned and currently-assigned Network Upgrades placed in service and identified system adjustments applied, no violations were observed, including violations of low-voltage ride-through requirements, for the probable contingencies studied.

CLUSTER GROUP 10 (SOUTHEAST OKLAHOMA/NORTHEAST TEXAS AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

The Group 10 cases included the following system adjustments of dispatching, to maximum output, generation interconnected at the same or adjacent substations to a current study request:

- Lieberman units: GEN-2016-167

The Group 10 stability analysis for this area was performed by Aneden Consulting (Aneden). With the new requests modeled, violations of stability damping criteria and voltage recovery criteria were observed.

The consultant reported the following:

- For certain contingencies at and near the POI, the GEN-2016-167 generator was tripped offline under both under and over frequency relays. Certain limitations within the generator stability model and/or low-inertia within the network can result in drastic changes to the bus reference angles which may then cause spikes in quantities such as the calculated frequencies. According to Siemens PTI, this is a well-known issue with the modeling of PV type devices in simulation software like PSS/E. Some of the frequency relay settings associated with GEN-2016-167 generator were adjusted to prevent the tripping of the generator caused by this modeling issue.

- The consultant observed that certain prior outage contingencies require curtailment of study generation as a system adjustment.

Prior to completion of Facility Study, the GEN-2016-167 customer must provide SPP with an updated model or fault simulation instructions from the inverter vendor that mitigates the simulation tripping identified.

With all previously-assigned and currently-assigned Network Upgrades placed in service and identified system adjustments applied, no violations were observed, including violations of low-voltage ride-through requirements, for the probable contingencies studied.

CLUSTER GROUP 12 (NORTHWEST ARKANSAS AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

The Group 12 stability analysis for this area was performed by ABB Inc. (ABB). With the new requests modeled, violations of stability damping criteria and voltage recovery criteria were observed.

For certain contingencies at and near the POI GEN-2016-166 tripped offline due to frequency relay initiated tripping. The Interconnection Customer (IC) should review with the generator vendor the frequency relay settings, including the frequency measurement location, as well as dynamic response of the inverter model to avoid such type of tripping.

Prior to completion of Facility Study, the GEN-2016-166 customer must provide SPP with an updated model or fault simulation instructions from the inverter vendor that mitigates the simulation tripping identified.

With all previously-assigned and currently-assigned Network Upgrades placed in service and identified system adjustments applied, no violations were observed, including violations of low-voltage ride-through requirements, for the probable contingencies studied.

CLUSTER GROUP 13 (NORTHEAST KANSAS/NORTHWEST MISSOURI AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

The Group 13 cases included the following system adjustments of dispatching, to maximum output, generation interconnected at the same or adjacent substations to a current study request:

- Sibley units: GEN-2016-088 & GEN-2016-115
- Nebraska City units: GEN-2016-088 & GEN-2016-115
- Iatan units: GEN-2016-149, GEN-2016-150, GEN-2016-174, & GEN-2016-176

- West Gardner units: GEN-2016-157 & GEN-2016-158
- Higginsville units: GEN-2016-168

The Group 13 stability analysis for this area was performed by POWER-tek Global Inc. (POWER-tek). With the new requests modeled, violations of stability damping criteria and voltage recovery criteria were observed.

For certain contingencies at and near the POI, GEN-2016-168 tripped offline due to frequency relay initiated tripping. The Interconnection Customer (IC) should review with the generator vendor the frequency relay settings, including the frequency measurement location, as well as dynamic response of the inverter model to avoid such type of tripping.

Prior to completion of Facility Study, the GEN-2016-168 customer must provide SPP with an updated model or fault simulation instructions from the inverter vendor that mitigates the simulation tripping identified.

The consultant noted that for the outage of the Holt to Nebraska City 345 kV circuit #1, system oscillations were observed. It was determined that the combination of the existing bus reactor switching set points and a voltage control response from the higher queued request GEN-2014-021 results in a stable response.

With all previously-assigned and currently-assigned Network Upgrades placed in service and identified system adjustments applied, no violations were observed, including violations of low-voltage ride-through requirements, for the probable contingencies studied.

CLUSTER GROUP 14 (SOUTH CENTRAL OKLAHOMA AREA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

The Group 14 cases included the following system adjustments of dispatching, to maximum output, generation interconnected at the same or adjacent substations to a current study request:

- Seminole units: GEN-2016-102 & GEN-2016-126
- Hugo Power Plant unit: GEN-2016-129

The Group 14 stability analysis for this area was performed by S&C. With the new requests modeled, violations of stability damping criteria and voltage recovery criteria were observed. Upgrades identified in the power flow analysis were also tested in the stability analysis.

Analysis of Group 14 dynamic simulation results showed that for some contingencies, the voltages in the area close to interconnection requests, GEN-2016-126 and GEN-2016-102, reach high voltages of 1.37 p.u. at the POI of GEN-2016-126 and other nearby buses, immediately following fault clearing. To mitigate the observed overvoltage instances, the base cases were updated to set GEN-2016-126 to inject 0 MVAR in the power flow case.

With all previously-assigned and currently-assigned Network Upgrades placed in service and identified system adjustments applied, no violations were observed, including violations of low-voltage ride-through requirements, for the probable contingencies studied.

CLUSTER GROUP 15 (EASTERN SOUTH DAKOTA)

In the event that the requested POI for GEN-2016-094 is not viable, this request may be incorporated into Group 15.

Generation in this area may require additional upgrades to relieve system reliability constraints related to NERC registered flowgate #6008. This flowgate requires additional review and updates resultant from the inclusion of the assigned network upgrades.

New requests for this study group as well as prior-queued requests are listed in Appendix C.

The Group 15 cases included the following system adjustments of dispatching, to maximum output, generation interconnected at the same or adjacent substations to a current study request:

- Aberdeen, Groton, & Redfield units: GEN-2016-164
- Big Bend & Leland Olds units: GEN-2016-092 & GEN-2016-103

The Group 15 stability analysis for this area was performed by Burns & McDonnell Engineering Company, Inc. (B&McD). With the new requests modeled, violations of stability damping criteria and voltage recovery criteria were observed. Upgrades identified in the power flow analysis were also tested in the stability analysis.

To mitigate the voltage instability, violations of voltage recovery criteria, and generation tripping off the following upgrades were implemented in each season:

- Addition of GEN-2016-017-Tap to Ft. Thompson 345kV 2nd circuit

The consultant also noted that for certain prior outage conditions curtailment (system adjustment) will be needed to maintain system stability for subsequent circuit outages.

With all previously-assigned and currently-assigned Network Upgrades placed in service and identified system adjustments applied, no violations were observed, including violations of low-voltage ride-through requirements, for the probable contingencies studied.

CLUSTER GROUP 16 (WESTERN NORTH DAKOTA)

New requests for this study group as well as prior-queued requests are listed in Appendix C.

The Group 16 cases included the following system adjustments of dispatching, to maximum output, generation interconnected at the same or adjacent substations to a current study request:

- Antelope Valley Station units: GEN-2016-108, GEN-2016-130
- Garrison & Leland Olds units: GEN-2016-130

The Group 16 stability analysis for this area was performed by POWER-tek Global Inc. (Power-tek). With the new requests modeled, violations of stability damping criteria and voltage recovery criteria were observed. Upgrades identified in the power flow analysis were also tested in the stability analysis.

To mitigate the voltage instability, violations of voltage recovery criteria, and generation tripping off the following upgrades were implemented in each season:

- Addition of a 2nd 345/230kV transformer at Tande station
- Addition of a new Emmons County 345kV substation along Antelope Valley Station to Broadland 345kV (500kV) and Fort Thompson to Leland Olds 345kV circuits
- Addition of a new McIntosh County 345kV substation along Groton to Leland Olds 345kV circuit
- Addition of a new approximately 45 mile Emmons County to McIntosh County 345kV circuit
- Upgrade Broadland 345kV (500kV) to Huron 230kV transformer

The consultant also noted that for certain prior outage conditions curtailment (system adjustment) will be needed to maintain system stability for subsequent circuit outages.

CLUSTER GROUP 17 (WESTERN SOUTH DAKOTA)

The requested POI for GEN-2016-094 may not be viable, additional analysis will be required to identify if additional mitigation is required with a POI at Ft. Thompson. The interconnection cost estimate is for a POI at Ft. Thompson. In the event that the requested POI for GEN-2016-094 is not viable, this request may be incorporated into Group 15.

New requests for this study group as well as prior-queued requests are listed in Appendix C.

The Group 17 cases included the following system adjustments of dispatching, to maximum output, generation interconnected at the same or adjacent substations to a current study request:

- Big Bend, Fort Randal, & OAHE units: GEN-2016-094

The Group 17 stability analysis for this area was performed by ABB Inc. (ABB). With the new requests modeled, violations of stability damping criteria and voltage recovery criteria were not observed.

There were no impacts on the stability performance of the SPP system.

With all previously-assigned and currently-assigned Network Upgrades placed in service, no violations were observed, including violations of low-voltage ride-through requirements, for the probable contingencies studied.

CLUSTER GROUP 18 (EASTERN NORTH DAKOTA)

No new interconnection requests in this group.

9.3 CURTAILMENT AND SYSTEM RELIABILITY

In no way does this study guarantee operation for all periods of time. It should be noted that although this study analyzed many of the most probable contingencies, it is not an all-inclusive list and cannot account for every operational situation. Because of this, it is likely that the Customer(s) may be required to reduce their generation output to 0 MW, also known as curtailment, under certain system conditions to allow system operators to maintain the reliability of the transmission network.

10 CONCLUSION

The minimum cost of interconnecting all new generation interconnection requests included in this Definitive Interconnection System Impact Study is estimated at **$6.212**Billion, not including the exceptions noted in Section 5.

Allocated costs for Network Upgrades and Transmission Owner Interconnection Facilities are listed in Appendix E and F. For Interconnection Requests that result in an interconnection to, or modification of, the transmission facilities of the Western-UGP (WAPA), a National Environmental Policy Act (NEPA) Environmental Review will be required. The Interconnection Customer will be required to execute an Environmental Review Agreement per Section 8.6.1 of the GIP.

These costs do not include the cost of upgrades of other transmission facilities listed in Appendix H which are Network Constraints. These interconnection costs do not include any cost of any Network Upgrades that are identified as required through the short circuit analysis. Potential over-duty circuit breakers capability will be identified by the Transmission Owner in the Interconnection Facilities Study.

Further refinement of total estimated interconnection costs will be provided, should the Interconnection Customer meet the requirements for acceptance and choose to move into the Interconnection Facilities Study following the posting of this DISIS. The Interconnection Facilities Study may include additional study analysis, additional facility upgrades not yet identified by this DISIS, such as circuit breaker replacements and affected system facilities, and further refinement of existing cost estimates.

The required interconnection costs listed in Appendices E, and F, and other upgrades associated with Network Constraints do not include all costs associated with the deliverability of the energy to final customers. These costs are determined by separate studies if the Customer submits a Transmission Service Request (TSR) through SPP's Open Access Same Time Information System (OASIS) as required by Attachment Z1 of the SPP Open Access Transmission Tariff (OATT).

11 APPENDICES

SOAH DOCKET NO. 473-19-6862

PUC DOCKET NO. 49737

PUBLIC UTILITY COMMISSION OF TEXAS

APPLICATION OF

SOUTHWESTERN ELECTRIC POWER COMPANY

FOR CERTIFICATE OF CONVENIENCE AND NECESSITY

AUTHORIZATION AND RELATED RELIEF FOR

THE ACQUISITION OF WIND GENERATION FACILITIES

REBUTTAL TESTIMONY OF

JOHN F. TORPEY

FOR

SOUTHWESTERN ELECTRIC POWER COMPANY

FEBRUARY 12, 2020

TESTIMONY INDEX

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, POSITION IN THE COMPANY, AND BUSINESS ADDRESS.

A. My name is John F. Torpey, and I am employed as Managing Director - Resource Planning and Operational Analysis for American Electric Power Service Corporation (AEPSC). AEPSC supplies engineering, financing, accounting, planning, and advisory services to the eleven electric operating companies of American Electric Power Company, Inc. (AEP), including Southwestern Electric Power Company (SWEPCO or the Company). My business address is 1 Riverside Plaza, Columbus, Ohio 43215.

Q. ARE YOU THE SAME JOHN F. TORPEY WHO FILED DIRECT TESTIMONY IN THIS CASE?

A. Yes, I am.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to address positions brought forward by Texas Industrial Energy Consumers (TIEC) witnesses Jeffry Pollock and Charles Griffey; Cities Advocating Reasonable Deregulation (CARD) witness Scott Norwood; and East Texas Electric Cooperative, Inc. and Northeast Texas Electric Cooperative, Inc. (ETEC/NTEC) witness James Striedel. Specifically, my rebuttal testimony explains why the Company's assumptions in the economic benefits analysis are more appropriate than the flawed assumptions proposed by TIEC, CARD, and ETEC/NTEC.

III. RESPONSE TO TIEC WITNESSES POLLOCK AND GRIFFEY

Q. WHAT IS YOUR GENERAL REACTION TO THE TESTIMONY BY TIEC WITNESSES POLLOCK AND GRIFFEY?

A. Messrs. Pollock and Griffey each start their analysis from an unreasonably low base point, then add more unlikely and pessimistic assumptions on top of that to produce an asserted benefit that is less than the cost of the proposed wind facilities, an outcome that is only remotely possible at best. At the same time, they ignore the more reasonable assumptions and forecasts presented by the Company that show the facilities will provide substantial net customer benefits. Indeed, if the Company put forth positive assumptions that were a mirror image of and equally likely as the TIEC witnesses' negative assumptions, the proposed wind facilities would produce enormous net benefits to customers. However, economic planning analysis should not strive to present extreme assumptions, either positive or negative, but to present reasonable forecasts bounded by appropriate sensitivity analyses.

Q. WHAT IS THE UNREASONABLY LOW BASE POINT FROM WHICH MESSRS. POLLOCK AND GRIFFEY BEGIN THEIR ANALYSIS?

A. Mr. Griffey begins with the benefits in the Company's Low Gas/No CO2 case (see Griffey p. 45, Figure 10), while Mr. Pollock generally begins with the P95 production level, rather than the expected P50 production level (see Pollock p.9). These starting points unreasonably bias their analysis right from the beginning, before they even begin considering their asserted adjustments to these benefit levels.

Q. WHY ARE THESE STARTING POINTS UNREASONABLY LOW?

A. Company witness Karl Bletzacker's rebuttal testimony addresses the flaws in assuming unrealistically low gas prices, but to be clear, the TIEC witnesses have effectively assumed a 0% probability of future carbon costs over the 30-year lives of the proposed wind facilities. While there is room for debate about the level of risk of future carbon costs, it certainly is not zero and could be far higher than that. Messrs. Pollock and Griffey are eager to assume risks that would reduce the benefits of the proposed facilities, but then they ignore offsetting risks that would increase the benefits.

Mr. Pollock's use of the P95 production level is another example. The P95 level of production is a very low level of energy production that will be met or exceeded 95% of the time. In other words, in only 5% of outcomes would production be below that level during any 5 year period. Mr. Pollock also assumes that output below the 95th percentile levels would repeat itself for six 5-year periods in a row for his analysis to be valid, which is an extremely low probability over the life of the project. Alternatively, the P5 capacity factor (i.e., a very high level of energy production) is just as likely as the P95 outcome Mr. Pollock uses throughout his testimony. The P5 capacity factor is 49%, which would result in 28% more energy production and PTCs than a P95 outcome, significantly increasing customer benefits.

The P50 level of production used in the Company's base case is the expected average. It is just as likely that the capacity factor will be higher than P50 than lower. While it is important to understand the downside risks of the Company's proposal, the Commission should give more weight to analytics based on a P50 level of output rather than a level that over any 5-year period has only a 5% chance of occurrence, as Mr.

Pollock does. Mr. Pollock does not challenge the wind analyses that support the Company's projected energy production levels.

Q. MR. GRIFFEY PREPARED AN ANALYSIS THAT ASSUMES A COMBINATION OF NEGATIVE IMPACTS ALL HAPPEN SIMULTANEOUSLY. HOW DO YOU RESPOND?

A. This overly negative "the sky is falling" analysis is not how utility resource planning has been or should be prepared. If any utility assumed all of those negative things happened simultaneously and utility commissions were persuaded by such an analysis, new resources would rarely if ever look economic. Testing the sensitivity of an investment opportunity to changes in assumptions should be done and was done by the Company under a wide range of assumptions, but not to the extreme degree of Mr. Griffey.

Acquisition of proposed wind facilities is a limited time opportunity, due to the phase out of the federal production tax credit (PTC), to invest capital that is expected to result in customers' bills going <u>down,</u> not up, even in the Company's most pessimistic scenarios. The PTCs these facilities will generate along with the energy value provide significant benefits to customers, especially during the first eleven years. The PTC credit is expected to average \$28/MWh. By grossing up the PTCs for the additional tax savings in ratemaking cost of service the PTC value alone equates to a \$37/MWh benefit for customers. As Company witness Thomas Brice points out, the Company is *guaranteeing* the initial construction costs and the PTCs on the greater of actual production or P95 production. This takes much of the uncertainty out of the analysis and mitigates PTC risk.

Wind assets are not completely reliant on the energy and capacity markets to provide revenues that offset their costs, like coal and gas units are. By receiving PTC value, assets like the proposed wind facilities significantly mitigate the market risk discussed by Messrs. Pollock and Griffey. These facilities generate an expected $963 million of grossed-up nominal PTC value for customers by 2031. This is front loaded, and because of the Company's PTC guarantee, this will occur regardless of what the energy market prices are. While the base forecast shows this up-front benefit could be offset by $212 million of nominal carrying charges on a deferred tax asset if the Company were unable to mitigate this cost, there is still $751 million of nominal value, which is not dependent on power prices, gas prices, or capacity value. The availability of PTCs for the proposed facilities makes them attractive relative to other resource options, provides significant value to customers, and is guaranteed by the Company.

Q. ARE THERE OTHER PROBLEMS WITH TIEC'S APPROACH OF ASSUMING THAT THEIR CUMULATIVE NEGATIVE ASSUMPTIONS ALL HAPPEN SIMULTANEOUSLY?

A. Yes. While there is a range of potential outcomes for each variable in the analysis, the possibility of all negative outcomes happening simultaneously is remote. For example, the probability of the proposed facilities producing at only a P95 production level is 5%, as discussed above. Multiplying this probability (.05) by a series of other low-probability occurrences (such as Mr. Griffey's asserted adjustments for a 25-year useful life, understated Company congestion assumptions, and no capacity benefit) produces a resulting probability of all events occurring simultaneously that is too small to be credible. It is not in customers' best interest to plan resources based on such a highly improbable combination of events. By using this approach, virtually no investment in beneficial resources would be made and the overall cost of serving customers would increase. Instead, prudent resource planning dictates that the Company make decisions based on the best information available at the time, considering reasonable sensitivities to stress test the benefits forecast. In this case, giving undue credence to an unlikely series of events that mathematically result in a net cost to customers would mean ignoring the much more probable and reasonable range of outcomes, based on actual analysis and studies, in which the proposed projects produce significant savings.

Q. BEFORE TURNING TO MR. POLLOCK'S AND MR. GRIFFEY'S SPECIFIC CONTENTIONS CONCERNING THE COMPANY'S BENEFITS FORECAST, DO YOU HAVE ANY OTHER GENERAL RESPONSE TO THEIR ASSERTION THAT VARIOUS ASSUMPTIONS CAUSE THE COMPANY'S FORECAST TO BE OVERSTATED?

A. Yes. It is highly doubtful that TIEC would agree to the reasonableness of SWEPCO assembling the converse "dream scenario" that makes a number of assumptions highly favorable to the projects, presumes they will all prevail simultaneously, and then concludes that customers stand to reap astronomical benefits from the projects. Such a scenario would not present meaningful information to the Commission regarding the value of the projects to customers or represent a prudent basis for resource planning. Yet, that is precisely the tack taken by these witnesses.

The Company recognizes that each party to this proceeding may have their own view of certain assumptions, such as future Southwest Power Pool (SPP) power prices and natural gas prices, so the Company determined a break-even power price for the proposed facilities. As shown in my Errata Testimony Figure 1, the proposed facilities will break even at a power price curve that averages only $21/MWh over the first ten years, regardless of the price of natural gas. This ten-year average break-even price is low when compared to the 2019 monthly average day ahead prices for the AEP zone of $25.00/MWh. This average break-even price is even lower than the lowest monthly price at this hub during all of 2019, $22.17/MWh for December 2019. Future SPP power prices would need to fall below that break-even line for an extended period for the projects not to be attractive. If, however there is a reasonable probability that power prices will be greater than break-even as they were in 2019 and as discussed in more detail by Company witness Bletzacker, then the project's total benefits will more than cover their costs.

IV. TIEC WITNESS POLLOCK

Q. MR. POLLOCK STATES THAT, AMONG OTHER THINGS, THE PROPOSED BENEFITS OF THE WIND PROJECTS CRITICALLY DEPEND ON DEFERRING FOSSIL-FUELED CAPACITY ADDITIONS (P. 9, L. 13). DO YOU AGREE?

A. No. While there are benefits associated with deferring future capacity additions, these benefits do not begin until 2038. The Company conservatively assumed the lowest tier of the proposed SPP capacity valuation criteria to determine these benefits. However, the benefits of the projects result primarily from production cost savings and PTCs, not capacity benefits.

Q. MR. POLLOCK (P.12, L. 8-11) ALSO STATES THAT THE CAPACITY BENEFIT ASSUMPTION IS SPECULATIVE AND PREMATURE BECAUSE THE SPP HAS

NOT ACCREDITED THE PROPOSED WIND PROJECTS AND THERE ARE NO APPROVED INTERCONNECTION AGREEMENTS. DO YOU HAVE ANY COMMENTS?

A. The capacity benefits are not assumed to occur until 2038 and at only 15% of the nameplate capacity, based on the methodology the SPP is expected to adopt. To assume that the capacity would not be accredited within 18 years is overly conservative. In addition, Mr. Pollock provides no reason why the projects' capacity value should be affected by the current status of their interconnection agreements. Company witness Richard Ross discusses obtaining firm transmission service in his rebuttal testimony.

Q. MR. POLLOCK STATES (P.10, L. 11) THAT 28% OF THE NOMINAL PRODUCTION COST BENEFITS OCCUR IN THE LAST FIVE YEARS OF THE PROJECT LIFE, AND RESULT FROM THE COMPANY USING A 30-YEAR LIFE VERSUS A 25-YEAR LIFE FOR THE PROJECTS. DO YOU HAVE ANY COMMENTS?

A. Yes. While Mr. Pollock's math is correct, the production cost benefits for the period 2047-2051, when discounted to net present value (NPV), actually represent only 12% of the production cost benefits. By presenting only the nominal benefits for the final years of the projects, Mr. Pollock makes these amounts appear larger than the NPV of those benefits. Company witness Joseph DeRuntz also addresses the projects' expected 30-year useful life in his rebuttal testimony.

Q. MR. POLLOCK (P.15, L. 2) STATES THAT THE USEFUL LIFE SHOULD REFLECT THE PERIOD OVER WHICH THE INITIAL CAPITAL INVESTMENT IS EXPECTED TO REMAIN IN SERVICE. IS THIS ASSUMPTION CONSISTENT

WITH USEFUL LIFE ASSUMPTIONS YOU MAKE FOR OTHER GENERATING ASSETS?

A. No. Generating assets, whether a combined cycle plant or wind facility, will have components replaced over time as the result of normal wear and tear, even with regular maintenance. Like a car that has tires, an alternator, or other parts replaced during its life, the useful life of the proposed facilities will be the period of time the facilities are in service, not just their initial components. The benefits analysis reflects all replacement costs and cost recovery during the 30-year period.

V. TIEC WITNESS GRIFFEY

Q. WHAT ARE MR. GRIFFEY'S ISSUES WITH THE COMPANY'S PROJECT BENEFITS CALCULATIONS?

A. Mr. Griffey asserts that a number of additional evaluation methods should have been considered in calculating the project benefits. These include the option to delay (p. 55-56), the payback approach (p. 56-60), the hurdle rate method (p. 61), and the risk-adjusted discount rate method (p.61-65). Mr. Griffey then asserts that applying these various methods in this case would result in a lower (or negative) customer benefit.

Q. DO YOU AGREE WITH MR. GRIFFEY'S RESULTS FROM THESE VARIOUS EVALUATION METHODS.

A. No. I have recently filed IRPs or been involved in certificate of need filings in eight states over the last two years and am not aware of any commission using any of Mr. Griffey's methods. In addition, Mr. Griffey's results depend on his input assumptions, which are not supported by the facts in this case. Company witnesses Johannes

Pfeifenberger and Noah Hollis also discuss Mr. Griffey's proposed analysis in their rebuttal testimony.

Q. PLEASE EXPLAIN HOW MR. GRIFFEY'S ASSUMPTIONS ARE NOT SUPPORTED BY THE FACTS IN THIS CASE WITH REGARD TO THE OPTION TO DELAY.

A. Mr. Griffey provides a very simplistic example (pages 55-56) of how waiting one year to enter into a Purchase Power Agreement (PPA), given future price uncertainty, has value. Based on the example provided, one would always wait one more year and never enter into a contract. More importantly, in the current filing, the option to wait comes at a cost of reduced or lost PTCs. For example, if the Company were to issue an RFP and receive bids on wind projects that only receive PTCs at the 60% level, the incremental wind energy cost (compared to current filing), would be, on average \$8.60/MWh more expensive. This theoretical future option is \$215 million more costly (on an NPV basis) than the current proposal by the Company. If the Company were to wait several years until PTC benefits were phased out altogether, the result would be the loss of \$751 million of PTC value as stated earlier. Mr. Griffey's assertion that the Company has the option to wait and still capture any upside benefits in the future (Griffey p. 55, L. 3-5) is simply wrong.

Q. PLEASE EXPLAIN HOW MR. GRIFFEY'S ASSUMPTIONS ARE NOT SUPPORTED BY THE FACTS WITH REGARD TO THE PAYBACK METHOD.

A. For the customer payback analysis to be valid there must first be a cash outlay by customers that they would then offset over time through benefits that resulted from that cash outlay. In the case of utility assets, customers do not outlay any cash up front beyond what they pay in rates for service, and therefore payback analyses from a customer's perspective are not used in utility economic analysis. In addition, a traditional payback period analysis from the perspective of the Company would start with the initial cash outlay, which in this case is about $1 billion for SWEPCO, and then determine the time it takes to recover that. Mr. Griffey has brought forward all 30 years of the facilities' revenue requirements and used that as the cost to be recovered. For these reasons, his analysis is invalid.

Mr. Griffey uses graphs to assert that it would take 27 years for the projects to "pay back" (Figures 12 and 13, Griffey pages 58 and 59). This does not accurately portray how customers will pay for the proposed projects' investment costs and receive the benefits. In Mr. Griffey's graphs, the total cost of the projects occurs in Year 0, while the benefits accrue over the life of the projects. Mr. Griffey's method may be appropriate if you were trying to decide between buying a lawnmower and hiring the kid next door to mow your lawn but does not represent the way SWEPCO's customers would see the projects' costs and benefits. Figure 1 below presents a more realistic view in nominal dollars from a customer perspective, showing project benefits under the Base – No Carbon pricing scenario, at both the P50 and P95 levels of production. At the likely P50 level, customers always receive a net benefit throughout the life of the projects, while even at the low P95 production level, the cost and benefit lines are on top of each other through 2031 (i.e., approximately break-even), diverge for a few years, and then customers receive a net benefit over the remaining project life. Figure 2 shows the same data on an NPV basis.

Figure 1
Nominal Annual Cumulative Customer Benefits Under Base No Carbon Pricing

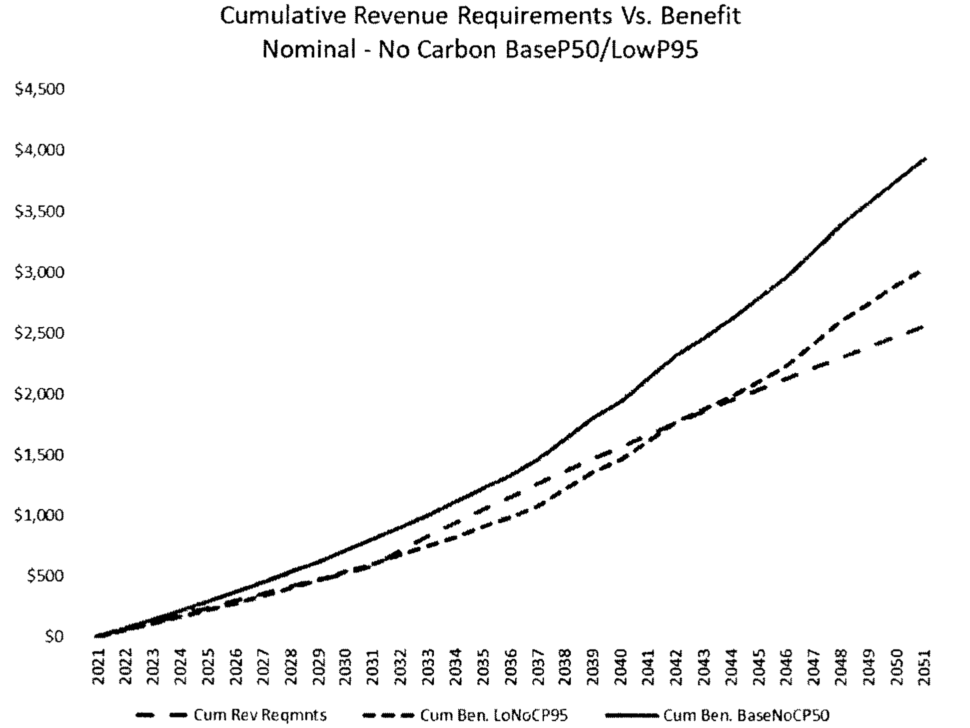
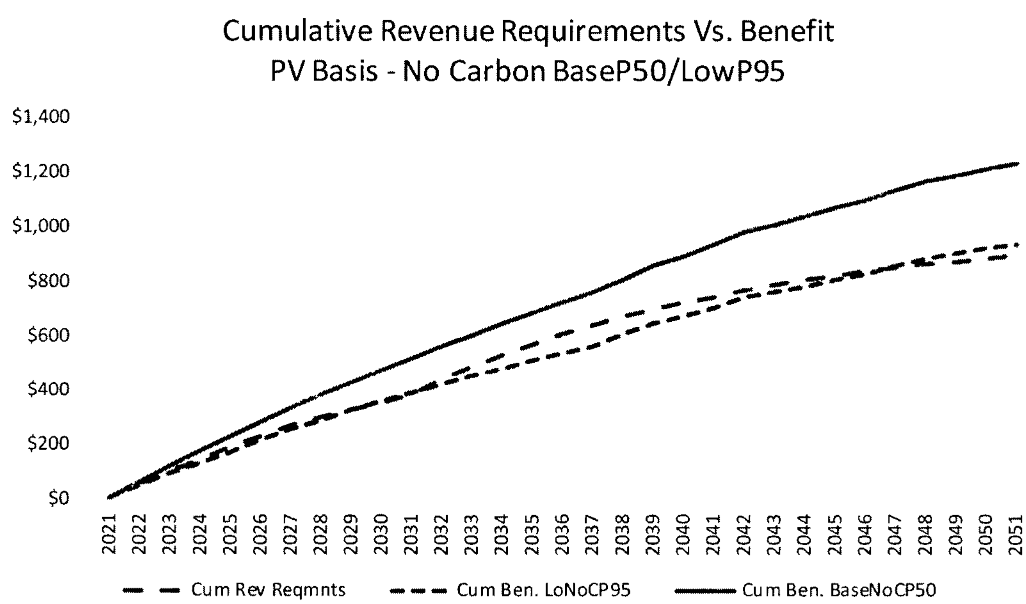


Figure 2
Present Value Annual Cumulative Benefits Under Base No Carbon Pricing



Q. MR. GRIFFEY ALSO ASSERTS (P. 60, L. 8-12 AND FIGURE 14) THAT ENERGY BENEFITS MAKE AN INCONGRUOUS 27% JUMP IN 2047. CAN YOU EXPLAIN THE INCREASE?

A. Yes. Mr. Griffey highlighted the only pricing scenario where this situation occurs (low gas NoCO2). In other pricing scenarios (such as the Base Gas, No Carbon or Base Gas scenario) this jump is not present. The reason behind the increase in benefits is simple – there is a difference in the timing between the "with wind" and "without wind" capacity plans of when new efficient natural gas plants that have very low fuel costs are added to replace older, retiring coal plants. This assumed plant replacement accounts for the sudden change in benefit.

Q. PLEASE EXPLAIN HOW MR. GRIFFEY'S ASSUMPTIONS ARE NOT SUPPORTED BY THE FACTS WITH REGARD TO THE HURDLE RATE METHOD.

A. The hurdle rate is the minimum rate of return on a project that provides appropriate compensation for the level of project risk. In SWEPCO's case, the Company is compensated for its risk at its Weighted Average Cost of Capital (WACC). The current project is similar to other power generation projects considered by the Company, which have historically been evaluated using the Company's WACC. However, Mr. Griffey calculates an internal rate of return on the benefits contribution of the project at 9.01%, which is a little less than 2% above the Company's WACC, and concludes this differential does not adequately compensate for the incremental risk. Even if Mr. Griffey's hurdle rate theory were valid, his analysis starts the calculation using the Company's Low Gas No CO_2 forecast, which already accounts for the risk of a low future price environment with no carbon penalty. This pricing scenario already takes most of the risk out of the projected benefits. In his rebuttal testimony, Company witness Hollis addresses issues around using a hurdle rate and Company witness Bletzacker addresses the concerns related to starting the analysis at a low price point.

Q. PLEASE EXPLAIN HOW MR. GRIFFEY'S ASSUMPTIONS ARE NOT SUPPORTED BY THE FACTS WITH REGARD TO THE RISK ADJUSTED DISCOUNT RATE METHOD.

A. Mr. Griffey's proposal to apply different discount rates to project costs and benefits should be rejected. The flaw in this method is that adjustments to the discount rate are very subjective making the resulting economics subject to the whims of the analyst. The projects present one investment opportunity, which should be discounted at one discount rate applicable to the entire opportunity, consistent with how utility resource planning has been done over my entire career. I am not aware of Mr. Griffey's method being used to evaluate projects in any of AEP's jurisdictions including Texas. Applying his method to all utility resource planning decisions would make it very difficult to gain Commission approval to build anything, even to keep up with load growth and replace retiring units.

Regardless of the discount rate, customers will pay cost-based rates and receive the benefits over time based on nominal PTC's and energy market revenues. This opportunity will deliver $2 billion worth of nominal net benefits to customers at the projects' projected average capacity factors, $751 million of which is PTC value (net of the DTA carrying cost). Mr. Griffey's proposed different discount rates for project costs and benefits would not affect the projects' actual (nominal) benefits to customers over the life of the projects. It is simply a way of manipulating the present value calculation to make the projects appear unfavorable.

Q. WHAT IS THE EFFECT ON CUSTOMER RISK OF USING DIFFERENT DISCOUNT RATES FOR COSTS AND BENEFITS AS MR. GRIFFEY PROPOSES?

A. Applying Mr. Griffey's differential discount rates increases risk to customers that beneficial projects will not be pursued due to unreasonably high analytical hurdles. If corresponding and offsetting risks occur, such as a CO_2 burden or increased power prices, customers will be harmed by foregoing the substantial benefits the projects would provide in those circumstances and instead paying more for power without the projects. While Mr. Griffey professes to mitigate customer risk, he actually increases that risk if the Commission does not approve beneficial facilities due to overly conservative or pessimistic analysis.

Q. MR. GRIFFEY (PAGES 62 AND 63) SUGGESTS THAT THE WACC THAT THE TEXAS COMPTROLLER USES FOR VALUING OIL AND GAS RESERVES IS APPROPRIATE AS A DISCOUNT RATE FOR THE NON-PTC BENEFITS OF THESE FACILITIES. HOW DO YOU RESPOND?

A. Mr. Griffey uses a discount rate that he found in the 2019 Property Value Study Discount Rate Range for Oil and Gas Properties. In this report, the Property Tax Assistance Division (PTAD) calculates a range of discount rates used to discount the projected future income of oil and gas produced from individual properties.

The PTAD first calculates the average WACC of 18 petroleum companies, including multinational companies such as Chevron, Conoco Phillips, Exxon Mobil, Hess, Occidental, Pioneer, and Cabot, to name a few. While Mr. Griffey asserts that the WACC of these petroleum companies is somehow related to natural gas prices, he does not establish any such relationship, much less that these WACCs correlate to variability of future SPP energy prices, or the riskiness of the Selected Wind Projects. The PTAD then takes the 18 petroleum companies' composite before income tax WACCs (using a 28/72 debt-equity split) and adds a two percent risk premium to establish the base rate for valuing oil and gas properties.

The range of discount rates reported by Mr. Griffey come from Table 2 of that report and is based on the average of discount rates using sources such as transactions from 1990 - 2005, survey responses from Survey of Parameters Used in Property Evaluation (June 2018), and the appraisal of 4,872 properties from 2018 Property Value Study. On page 62 Mr. Griffey notes that "The Comptroller then adds risk premia for a variety of other risks (single field risk, etc.)," without offering further information about these criteria, which undermines his entire argument.

Mr. Griffey's analysis suggests that simply because power prices have a degree of correlation with gas prices, discount rates for the proposed wind facilities production cost savings should be similar to multi-national companies engaged in unregulated oil and gas production. However, oil and gas producers face risks so different from electric utilities that it is impossible to compare the two with any confidence or to conclude that such a comparison is meaningful. Even if it were valid to suggest that WACC's used in the petroleum industry to value reserves are somehow indicative of a regulated utility investment risk, which it is not, oil risk is not the same as natural gas risk. These companies face different risks than consumers of natural gas. It should be obvious that multi-national petroleum companies' risks are different from regulated utility investment risk.

Q. IS THE RISK ADJUSTED DISCOUNT RATE USED BY MR. GRIFFEY APPROPRIATE FOR THE FUTURE PRODUCTION COST SAVINGS?

A. No. Mr. Griffey asserts that a risk-adjusted discount rate may be used to adjust for systematic risk of future cash flow. However, once again Mr. Griffey starts with the Company's lowest energy price forecasts before applying his higher discount rate. Even if Mr. Griffey's multi-national petroleum company discount rate proposal had any validity, he is in effect double counting the discount. Had he applied his higher discount factor to the Company's Base Gas No CO_2 forecast, the wind facilities would still produce customer benefits of $126 million NPV. SWEPCO's analysis in this case is consistent with the approach used by Southwest Public Service in Docket No. 46936, which used a single discount rate and different sensitivity cases to evaluate the risk of the proposed facility. The settlement in that case was supported by TIEC and approved by the Commission.

VI. CARD WITNESS NORWOOD

Q. DID MR. NORWOOD OFFER AN OPINION ON THE COST/BENEFIT ANALYSIS PERFORMED BY THE COMPANY?

A. Yes. Mr. Norwood (p.4, l. 10-12) found that the cost/benefit analysis was conducted using industry standard production cost models, and the modeling process and range of scenarios evaluated generally appear to be reasonable.

Q. MR. NORWOOD (P. 5, L. 17-18) DOES NOT RECOMMEND APPROVAL OF THE PROJECT, IN PART BECAUSE THE COMPANY IS FORECASTED TO HAVE EXCESS CAPACITY UNTIL 2026. HOW DO YOU RESPOND?

A. Resource planning models select wind projects primarily for their energy value. In the SWEPCO IRPs prepared in 2018 and 2019, portfolios with wind projects (with PTCs) result in lower revenue requirements than portfolios without wind. The objective of an IRP is to select a portfolio that not only meets the Company's capacity obligation but also does so at the lowest reasonable cost. Adding wind projects that qualify for the PTC accomplishes that objective. Although the proposed wind facilities do provide capacity cost savings, their benefits are largely due to energy cost savings and PTCs. If SWEPCO were to wait until 2026 to acquire wind assets, it would not realize the benefits from the PTCs.

Q. MR. NORWOOD IS CONCERNED THAT THE COMPANY'S 2018 IRP ANALYSIS OVERSTATED THE VALUE AND OPTIMAL QUANTITY OF WIND BECAUSE THAT IRP USED A FORECAST WITH HIGHER ENERGY COSTS THAN THE CURRENT 2019 FORECAST. CAN YOU COMMENT?

A. While the Company developed the 2018 Arkansas IRP and draft Louisiana IRP using the 2018 forecast, the Company completed the final Louisiana IRP in August 2019, after this application was filed. The 2019 Louisiana IRP used the same commodity price forecast as in this filing and selected a similar level of wind resources by 2023 and over the study period.

VII. ETEC/NTEC WITNESS STRIEDEL

Q. MR. STRIEDEL FAULTS THE COMPANY FOR NOT REFLECTING THE RECENTLY ANNOUNCED 2026 RETIREMENT OF DOLET HILLS IN ITS ECONOMIC EVALUATION. DOES THE DOLET HILLS ANNOUNCEMENT ALTER THE WIND FACILITY ECONOMICS?

A. No. Had the Dolet Hills decision been finalized prior to this application, the analysis would have shown the Dolet Hills retirement in both the "with wind" and "without wind" cases. The level of existing SWEPCO unit generation is based on SPP market prices and is not affected by the presence of the wind facilities. Dolet Hills operates seasonally in the model at a relatively low capacity factor. If Dolet Hills were removed from the analysis the capacity benefit from the wind may have occurred sooner, which would result in an increased benefit for the projects. If the Company were to rerun its analysis to exclude Dolet Hills, while there may be a slight difference in production costs in both the with and without wind cases, I would expect the benefits of these wind facilities to be comparable to this filing. Moreover, in the absence of Dolet Hills, the proposed wind facilities will mitigate any additional risk of relying on higher seasonal market energy prices.

VIII. CONCLUSION

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does.

SOAH DOCKET NO. 473-19-6862

PUC DOCKET NO. 49737

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FEBRUARY 12, 2020

TESTIMONY INDEX

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, TITLE, EMPLOYER, AND BUSINESS ADDRESS.

A. My name is Johannes P. Pfeifenberger. I am a Principal at the Brattle Group, and I am based in the company's Boston office. My business address is One Beacon Street, Suite 2600, Boston, MA 02108. I previously submitted direct testimony in this proceeding on behalf of the Southwestern Electric Power Company (SWEPCO or the Company).

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to positions brought forward by Texas Industrial Energy Consumers (TIEC) witnesses Jeffry Pollock and Charles Griffey, and East Texas Electric Cooperative, Inc. and North Texas Electric Cooperative, Inc. (collectively, ETEC) witness John Chiles. Specifically, my rebuttal testimony addresses and explains the following in response to these witnesses:

- Mr. Pollock claims that the Company's Southwest Power Pool (SPP) market prices are overstated in part because the simulations do not include enough renewable generation investments in the SPP footprint. This claim is not supported and inconsistent with the following facts: (1) SPP staff and stakeholders have carefully developed the 2024 and 2029 modeling assumptions that formed the basis for the Company's analysis, which was supplemented with the Traverse facility; (2) Mr. Pollock's analysis of wind generation overstates the certainty of wind addition and does not consider the high level of solar generation additions already in SPP's model assumptions; (3) as Company analysis and a recent independent study demonstrate, adding wind generation has a relatively small effect on wholesale prices in the SWEPCO service area; and (4) Mr. Pollock does not consider the potential for additional retirements of coal generation in the SPP footprint, particularly at the unrealistically low natural gas prices the TIEC witnesses assume. The impact of additional coal retirements and fewer renewable generation additions than Mr. Pollock assumes would offset the reduction of wholesale power prices discussed by the TIEC witnesses.

- Mr. Griffey suggests it is reasonable to assume that congestion costs from the Selected Wind Facilities would continue to increase over the 30-year life of the facilities. However, assuming such a continued increase in congestion is unreasonable given (1) the level of innovation and new technologies in the transmission industry, and (2) the fact that the Company can avoid such cost increases through the construction of a gen-tie.

- Contrary to Mr. Griffey's suggestion, it is unreasonable to discount customer benefits of the Selected Wind Facilities at a much higher rate than their costs. As I discuss, Company ownership of the Selected Wind Facilities will *decrease* (not increase) customer risks—which means that, if an adjustment to the discount rate were justified, it would be a decrease (not an increase). Applying different discount rates for benefits and costs is also inconsistent with standard industry practice, including with how discount rates have been selected and used in a similar case that has been approved by this Commission with TIEC support.
- Mr. Chiles' suggestion that the Company should not have relied on AURORA simulation but should instead have simulated 10 scenarios in PROMOD is unreasonable, impractical, and unnecessary given that the Company's approach of using three models with unique individual advantages yields reasonable estimates of market prices and congestion differentials. Mr. Chiles' suggestion that the Company should have assumed that none of the wind delivery-related congestion costs would be hedged is unreasonable, as the Company's assumption is based on (and lower than) data of actual Transmission Congestion Rights (TCR) hedge realized in 2018 by SWEPCO's and Public Service Company of Oklahoma's (PSO's) contracted existing wind generation resources in the SPP footprint.

II. IMPACT OF ADDITIONAL WIND GENERATION ON SPP MARKET PRICES

Q. TIEC WITNESS POLLOCK STATES ON PAGE 29 OF HIS DIRECT TESTIMONY THAT SWEPCO UNDERSTATED THE INFLUX OF RENEWABLE ENERGY RESOURCES IN SPP, AND AS A RESULT, OVERSTATED THE LOCATIONAL MARGINAL MARKET PRICES. WHAT IS MR. POLLOCK'S BASIS FOR THIS ASSERTION?

A. Mr. Pollock notes that SWEPCO assumed 6.4 GW and 8.8 GW of additional renewable capacity would come online by 2024 and 2029, respectively. He states that there is currently more renewable capacity in SPP's generation interconnection queue, some of which already has fully executed Generation Interconnection Agreements (GIAs) and is on schedule to enter commercial operation between 2019 and 2020. He notes that additional renewable resources are currently in the "Facility Study Stage" and in the "Definitive

Interconnection System Impact Study (DISIS) stage". Mr. Pollock asserts that if certain percentages of this planned capacity were to materialize, renewable resource additions would exceed 15 GW. Mr. Pollock also presents an alternative theory in which renewable resource additions in SPP would total 14 GW.

Q. DO YOU AGREE WITH MR. POLLOCK'S CLAIM THAT SWEPCO UNDERSTATED FUTURE RENEWABLE CAPACITY ADDITIONS IN SPP?

A. No, I do not. As I explained in my direct testimony, the Company relied on SPP's PROMOD "Reference Case (Future 1)," which was developed by SPP staff and stakeholders for the 2019 Integrated Transmission Planning (ITP) process. SPP's 2019 ITP PROMOD models include all planned and/or needed future generating resources, including renewable generation resources at levels and locations that SPP and its stakeholders have deemed feasible and realistic for development by 2024 and 2029. As noted in my direct testimony, SPP and its stakeholders projected a total of 24,200 MW of installed wind generation for 2024 and 24,600 MW by 2029 in the Reference Case. They assumed solar generation in the footprint to grow from approximately 250 MW today to 3,000 MW in 2024 and to 5,000 MW in 2029. Further, SPP notes that its Reference Case reflects a continuation of current industry trends and environmental regulations, and reflects SPP and its stakeholders' general expectations about the future state of the market.

Similarly, SPP's 2019 ITP Assessment Report, which was published in November 2019, reported that SPP employed this same Reference Case PROMOD model for the economic evaluation of future transmission system needs, and that the SPP Board approved

$336.7 million in transmission investments[1] based on an expected benefit-to-cost ratio of 3.5 under these SPP Reference Case analyses. The Assessment Report notes that SPP conducted a more in-depth analysis in the 2019 ITP study with the goal "to better forecast renewables development, which will allow the region to proactively build the infrastructure needed to alleviate congestion and provide access to less expensive energy."[2] This suggests that the future renewable generation assumptions in the SPP Reference Case were vetted extensively and found to be appropriate for use in assessing the costs and benefits of SPP's transmission portfolio.

For these reasons, I believe that the SPP Reference Case assumptions for future renewable generation were the most reasonable starting point for SWEPCO's analysis of its Selected Wind Facilities. To these SPP Reference Case assumptions, SWEPCO's analysis subsequently added 1,000 MW of projects that were not already reflected in SPP's PROMOD models based upon an actual market bidding request under the Company's request for proposals.[3] In this way, the Company both relied upon the stakeholder-vetted SPP model and the actual market response of commercial wind projects in its analysis. I believe these SPP-vetted assumptions, supplemented by actual market response, are a much more reasonable basis for the Company's analysis than Mr. Pollock's postulated levels of future wind generation development based on a percentage of SPP queued renewable generation.

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1 See Page 93 of the SPP 2019 ITP Assessment Report, November 06, 2019 https://www.spp.org/documents/60937/2019%20itp%20report_v1.0.pdf

2 See Page 2 of the SPP 2019 ITP Assessment Report, November 06, 2019.

3 The Company's PROMOD modeling assumptions reflect the 1 GW capacity of Traverse in addition to the future wind capacity assumed in the SPP Reference Case.

Q. ARE THERE ANY REASONS MR. POLLOCK'S ASSUMED LEVELS OF RENEWABLE GENERATION MAY BE UNREASONABLE?

A. Yes. First, Mr. Pollock's assumptions that 50% of the queued renewable projects in the "Facility Study" stage and 5% of those in the "DISIS" stage would come to fruition are unsupported. Commercial development of projects still in the Facility Study or DISIS stage is speculative, and therefore should not be considered for long-term planning purposes, unless more information regarding any specific projects are available. Second, even a fully executed GIA with an "on schedule" interconnection status does not guarantee that a renewable resource will actually go into commercial operation by its expected date, if at all. For example, within less than a month of Mr. Pollock's review of the then-current SPP generation interconnection queue, 251 MW of "on schedule" wind generation in Mr. Pollack's data has been suspended.[4] These status changes are consistent with historical variability in the SPP queue, even when focusing on resources with fully executed GIAs with "on schedule" status, which are well advanced in the SPP generation interconnection queue beyond the "Facility" and "DISIS" study stages. For instance, SPP's queue as of February 2019 projected that 2,654 MW of renewable resources were on schedule to go into commercial operation in 2019. However, nearly a year later, SPP's queue reports that only 1,584 MW of renewable resources actually went into commercial operation in 2019.[5]

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[4] See workpaper "Pfeifenberger WP-R-1 - Figure 1.xlsx" comparing the SPP Generation Interconnection Active Request Listings as of December 23, 2019 (from M. Pollock's workpaper, "GI_ActiveRequest 122319.xlsx") and January 16, 2020.

[5] Of these 1,584 MW wind resources, 1,214 MW have a commercial operation date of 2019, while one 370 MW resource reports a 2021 commercial operation date. I assume that this project achieved commercial operation early, and conservatively include it in the 2019 total. In addition, of the specific 2,654 MW of renewable resources in the February 2019 queue, 1,014 MW have an updated commercial operation status, while 759 MW are still shown on schedule but have lapsed their commercial operation date, and another 881 MW have been delayed or suspended.

Clearly, even resources with fully executed GIAs that are listed as "on schedule" lack the level of certainty that Mr. Pollock suggests.

Moreover, Mr. Pollock's 10 GW of assumed renewable resource additions (i.e., those with fully executed GIAs and "on schedule" status) consist almost entirely of wind resources, which is inconsistent with SPP's projections in the 2019 ITP Reference Case, which contains less wind but significantly more solar generation. While the SPP generation interconnection queue only contains 260 MW of expected solar resources with fully executed GIAs, SPP and its stakeholders have projected (and reflected in the SPP PROMOD models) that installed solar generation will grow from approximately 250 MW today to 3,000 MW in 2024 and to 5,000 MW in 2029. We understand that this shift from wind to solar generation was a conscious decision of SPP stakeholders to reflect the fact that tax incentives for wind generation phase out more quickly than the tax incentives available to solar generation. This additional SPP-projected solar generation also means that the SPP PROMOD model has more solar generation than Mr. Pollock seems to recognize in his testimony by focusing only on wind generation.

Given these circumstances, I believe it was reasonable for the Company to rely on the stakeholder-vetted assumptions in the SPP PROMOD Reference Case, which were supplemented by the Company's actual market response, rather than assume that a different amount of future resources would develop in the SPP based on some assumed probability level applied to the generation interconnection queue. Since the wind and solar generation amounts in the Company's AURORA model are similar to those in the SPP PROMOD Reference Case (as acknowledged by Mr. Pollock on page 31 of his testimony), I conclude that the AURORA model likewise reflects reasonable levels of renewable resource additions.

That said, in the event that the consensus view among SPP staff and stakeholders ends up understating renewable generation development in the SPP—and by consequence those reflected in the Company's PROMOD and AURORA models, that shortfall would only be a modest share of all queued wind and solar generation. As Mr. Pollock notes in his direct testimony, SPP's Market Monitor reported 20.8 GW of renewable generation were in commercial operation at the end of 2018. Even ignoring the uncertainty of projects in the SPP generation queue and assuming that 100% of the 9.8 GW of all on schedule renewables in the current queue will become operational by the end of 2023[6], this would yield a total of 30.6 GW of renewable resources. Figure 1 below compares this estimated amount to the renewable levels modeled in both SPP'S PROMOD and the Company's AURORA models.

Figure 1: Comparison of SPP Existing and "On Schedule" Generation with SPP's PROMOD and the Company's AURORA Assumptions

		GW	
Current SPP renewables and all "on schedule" renewables in SPP Queue			
SPP renewables in commercial operation as of end of 2018	[1]	20.8	
All "on schedule" renewables in SPP queue	[2]	9.8	
Total renewables on schedule to be operational by end of 2021	[3]	30.6	
Total renewables with fully executed GIAs scheduled for 2022-2029	[4]	0.0	
PROMOD/AURORA Models		*PROMOD*	*AURORA*
Renewables in Model for 2024	[5]	28.2	27.8
Renewables in Model for 2029	[6]	30.6	28.9

Sources and Notes:

[2]: Includes renewable resources (solar, wind, battery) in SPP queue as of January 16, 2020 with a GIA fully executed Commercial Operation/On Schedule status. All such renewable resources have a commercial operation date between 2019 and 2021

[3]: Excludes four plants that have a commercial operation date in 2021 but do not yet have a fully executed GIA

[5]-[6]: PROMOD modeling assumptions reflect the 1 GW capacity of Traverse on top of the wind capacity in the SPP Reference Case

6 Given that only approximately 60% of queued renewables that had commercial operation dates in 2019 as of February 22, 2019 came online in 2019, it may be unrealistic to expect that all 9.8 GW of "on schedule" queued renewables will become operational by the end of 2021.

As shown, even if there were an understatement in renewable capacity in the Company's analyses, it only would range between 2.4 GW and 2.8 GW by 2024. As discussed below, modeling an additional 2.4 GW or 2.8 GW of additional renewable resources would not have a significant impact on SPP market prices or the Company's estimate of the Selected Wind Facilities' benefits.

Q. HOW DO YOU RESPOND TO MR. POLLOCK'S CLAIM THAT MODELING ADDITIONAL RENEWABLE GENERATION RESOURCES WITHIN SPP WOULD HAVE RESULTED IN LOWER MARKET PRICES, THEREBY REDUCING THE ESTIMATED BENEFITS OF THE SELECTED WIND FACILITIES?

A. As explained above, I believe that the Company's modeled wind and solar generation levels based on SPP's ITP forecasts are reasonable in both the PROMOD and AURORA models. However, even if this were not the case, I disagree with Mr. Pollock's assertions that understating renewable generation resources would have significantly inflated market prices and reduced the benefits of the Selected Wind Facilities. While the addition of more renewable generation will tend to reduce market prices, such a reduction would be most pronounced in the wind-rich western portion of the SPP region, rather than the eastern portion where most of the Company's load is located. This is because the additional wind generation suggested by Mr. Pollock would increase congestion associated with the delivery of the wind plants' output to SPP's load centers in the east. Additional solar generation has a more direct impact on market prices in eastern SPP because solar generation is also projected to be developed in eastern Oklahoma, eastern Kansas, and western Missouri, but the SPP PROMOD model already includes significantly more solar than what Mr. Pollock's analysis of SPP's generation queue would add. Moreover, independent studies (discussed below) indicate that even in regions with significantly higher solar penetration than SPP— such as in CAISO and ISO-NE—the market price impact of solar generation is only modest, ranging from $0.16 to $0.17/MWh reduction for each percent of solar penetration in the overall generation mix.

Q. HAVE YOU ESTIMATED THE EFFECT THAT ADDITIONAL WIND GENERATION IN THE SPP FOOTPRINT WOULD HAVE ON MARKET PRICES IN THE COMPANY'S LOAD ZONE?

A. Yes, I have. To estimate the impact additional wind generation has on market prices in SPP—and hence Mr. Pollock's claimed understatement of market prices in the Company's analyses—I compared the results of the Company's PROMOD simulations for the RFP Bid Evaluation case and the Selected Wind Facilities' benefits analysis case using the "No- SPP- Upgrades" case. As explained in my direct testimony, the Company's Bid Evaluation case added 4,400 MW of RFP bids to the 24,200 MW wind capacity in the SPP Reference Case in 2024 and to the 24,600 MW wind capacity in 2029. In contrast, the Company's "No-SPP-Upgrades" case used in the customer benefits of the Selected Wind Facilities added only 1,000 MW of additional wind capacity (to account for the Selected Wind Facilities not in the SPP Reference Case) to the SPP Reference Case. In both cases, the Company assumed that, except for one upgrade, none of the SPP-ITP-identified transmission needs would be addressed. Therefore, the only difference between the Bid Evaluation and the "No- SPP- Upgrades" PROMOD simulation cases was that the Bid Evaluation case included an additional 3,400 MW of wind capacity in Oklahoma. A comparison of the simulation results for these two cases allows me to estimate the impact of adding 3,400 MW of additional queued wind capacity to the SPP footprint.

As illustrated in Figure 2 below, the additional 3,400 MW of wind capacity in SPP will reduce market prices in the AEP load zone[7] in 2024 and 2029 by $0.51/MWh and 0.75/MWh, respectively. These LMP reductions reflect a less than 2% load-zone price impact from the 3,400 MW of additional wind capacity in Oklahoma. This means that additional wind deployment in SPP will only very modestly reduce the SPP wholesale market prices faced by the Company's loads in eastern SPP. Additionally, the LMPs at the Company's generating facilities are reduced by only $0.16/MWh in 2024 and $0.04/MWh in 2029, or between 0.01% and 0.5% percent of SPP's wholesale market prices. Therefore, and contrary to Mr. Pollock's assumption, the impact of additional renewable generation, and in particular that of wind generation, in SPP has only a small impact on the Company's load zone and generation market prices.

Figure 2: Impact of 3,400 MW of Additional SPP Wind Generation on AEP Load Zone and SWEPCO Generation Zone LMPs (2024 and 2029)

	No SPP Upgrades Case *(Total SPP Wind + 1,000 MW Traverse [1])*		Bid Evaluation Case *(Total SPP Wind + 4,400 MW RFP Bids)*		Price Impact of 3,400 MW of Additional SPP Wind	
	[A]	[B]	[C]	[D]	[C-A]	[D-B]
	2024	**2029**	**2024**	**2029**	**2024**	**2029**
SPP Wind Generation (MW)	25,200	25,600	28,600	29,000	3,400	3,400
Simple Average LMP ($/MWh)						
SWEPCO Gen Zone	$31.92	$37.80	$31.76	$37.76	-$0.16	-$0.04
AEP Load Zone	$32.24	$38.90	$31.73	$38.15	-$0.51	-$0.74

Notes: [1]The Company only added 1,000 MW of additional wind capacity to reflect Traverse, because the other two Selected Wind Facilities, Maverick and Sundance, are already included in the SPP Reference Case.

[7] Throughout this testimony, I use "AEP load zone" to refer to the SPP-defined "AEP West Load Zone."

Q. IS THIS MODEST IMPACT OF ADDING ADDITIONAL SPP WIND GENERATION ON SPP MARKET PRICES CONSISTENT WITH OTHER STUDIES OF SUCH IMPACTS?

A. Yes. A November 2019 study by the Lawrence Berkeley National Laboratory (LBNL Study)[8] assessed the degree to which variable renewable energy (VRE) growth has influenced wholesale power energy prices between 2008 and 2017. The LBNL Study disentangled the relative contributions of different factors to observed reductions in market prices, and computed the individual impacts by market and type of VRE as summarized in Figure 3 below. The LBNL Study found that for SPP, the price impact of all wind generation was -$1.3/MWh, corresponding to a price reduction of approximately $0.05/MWh for each one percent of wind penetration. Across all markets and types of VRE, the LBNL Study calculated that each incremental increase in VRE penetration reduced average annual wholesale prices in 2017 by approximately $0.14/MWh.[9]

Figure 3: Impact of VRE Growth on Annual Average Wholesale Prices (2008-2017)

	Price Impact ($/MWh)		2017 Penetration (%)		Price Impact ($/MWh/%)	
	[A]	[B]	[C]	[D]	[A]/[C]	[B]/[D]
	Wind	Solar	Wind	Solar	Wind	Solar
CAISO	-$0.40	-$2.20	4.5%	13.5%	-$0.09	-$0.16
ERCOT	-$1.00	-$0.10	17.4%	0.7%	-$0.06	-$0.14
SPP	-$1.30	$0.00	25.3%	0.2%	-$0.05	$0.00
MISO	-$0.60	$0.00	7.7%	0.2%	-$0.08	$0.00
PJM	-$0.20	-$0.20	2.7%	0.9%	-$0.07	-$0.22
NYISO	-$0.30	-$0.20	2.7%	0.8%	-$0.11	-$0.25
ISO-NE	-$0.50	-$0.40	2.8%	2.4%	-$0.18	-$0.17

Sources and Notes:

LNBL Study (2019), available at https://eta-publications.lbl.gov/sites/default/files/lbnl_-_wind_and_solar_impacts_on_wholesale_prices_approved.pdf.

[A]-[B]: Price impacts from LBNL Study, Figure 6; [C]-[D]: Renewable penetrations from LBNL Study, Appendix A.

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8 Available at: https://eta-publications.lbl.gov/sites/default/files/lbnl_-_wind_and_solar_impacts_on_wholesale_prices_approved.pdf

9 LBNL Study, p. 16.

The addition of 3,400 MW of wind would add approximately 13.6 TWh of renewable generation to the SPP footprint, which is approximately 4.8% of the 280.5 TWh of total net energy for load in SPP's 2024 PROMOD model. By multiplying LBNL's \$0.14/MWh/% average by 4.8, the impact of adding 3,400 MW of wind to the SPP footprint would be \$0.67/MWh based on the LBNL Study. This \$0.67/MWh impact is an SPP-wide average and only slightly larger than the \$0.51/MWh impact estimated based on the Company's SPP PROMOD simulations shown in Figure 2 above.

Q. MR. POLLOCK (ON PAGE 31) STATES THAT SWEPCO'S ANALYSIS DOES NOT CAPTURE THE IMPACT ANY POST-2029 TRANSMISSION UPGRADES IN SPP WOULD HAVE ON THE PRICE DIFFERENTIAL BETWEEN SPP CENTRAL AND THE AEP LOAD ZONE. HE STATES THAT SUCH FUTURE SPP TRANSMISSION UPGRADES WOULD REDUCE THESE PRICE DIFFERENTIALS, SUGGESTING THAT THE COMPANY'S PROJECTED PRICES FOR LOAD AND GENERATION ARE OVERSTATED. DO YOU AGREE?

A. No. As explained in Company witness Sheilendranath's direct testimony, to reflect estimated congestion and loss-related costs between SPP Central and AEP load and SWEPCO generation zones, Mr. Sheilendranath calculated PROMOD price differentials on a percentage basis from the PROMOD SPP Central zone to the AEP load zone, and the SWEPCO generation zone, using SPP PROMOD models for 2024 and 2029. Applying these price differentials, he developed the AURORA prices for SWEPCO generation zone, and for the AEP load zone, for years 2024 and 2029. For the out years beyond 2029, Mr. Sheilendranath maintained the 2029 adjustments. I find this methodology to be appropriate, and do not believe that maintaining the 2029 percentage price differential adjustments for the 2030-2051 period would result in overstated prices for the AEP load and SWEPCO generation zones. For example, if more wind generation were to develop in SPP beyond 2030, the percentage price differentials from SPP Central zone to the AEP load zone would likely increase. I agree with Mr. Pollock that SPP would advance new transmission upgrades, which would have the effect of reducing the price differential. However, for the percentage price differentials to decline from the modeled 2029 level, it must mean that SPP will advance new transmission upgrades at a faster pace after 2030 than they are now. There is no evidence of this, therefore it is more conservative to assume that SPP's pace of future upgrades will match the current pace to alleviate future congestion if more wind generation develops in the SPP footprint beyond 2030.

Using the same methodology as in Figure 2 earlier shows that the impact of additional wind in SPP on the price differential between SPP Central and the AEP load zone can be significant. As illustrated in Figure 4 below, the impact of the additional 3,400 MW of wind capacity in the Bid Evaluation case compared to the "No-SPP-Upgrades" case is an increase in the SPP Central to AEP load zone price differential from \$5.53/MWh (16.6% of the SPP Central LMP) to \$7.06/MWh (22.7% of the SPP Central LMP). This represents a 37% increase in the price differential between SPP Central and the AEP load zone in 2029 due to the additional wind capacity.

Figure 4: Impact of 3,400 MW of Additional SPP Wind Generation on AEP Load Zone to SPP Central LMP Differentials

	No SPP Upgrades Case *(Total SPP Wind + 1,000 MW Traverse[1])*		Bid Evaluation Case *(Total SPP Wind + 4,400 MW RFP Bids)*		Price Impact of 3,400 MW of Additional SPP Wind	
	[A]	[B]	[C]	[D]	[C-A]	[D-B]
	2024	**2029**	**2024**	**2029**	**2024**	**2029**
SPP Wind Generation (MW)	25,200	25,600	28,600	29,000	3,400	3,400
Simple Average LMP ($/MWh)						
SPP Central	$28.06	$33.37	$25.80	$31.09	-$2.26	-$2.28
AEP Load Zone	$32.24	$38.90	$31.73	$38.15	-$0.51	-$0.74
Average LMP Differential ($/MWh)						
AEP Load Zone to SPP Central	*$4.17*	*$5.53*	*$5.93*	*$7.06*	*$1.76*	*$1.54*

To result in lower SPP market prices for the Company, SPP would not only need to advance new transmission upgrades to counter this 37% increase in price differential, but would need to build additional upgrades to reduce it from the 2029 levels (12.9%[10]) estimated in the PROMOD "Base Case" (or 16.6% in the "No-SPP-Upgrades Case") employed in the customer benefits analysis. I find this to be an unlikely outcome.

Q. MR. POLLOCK CLAIMS THAT HIS CASE FOR OVERSTATED MARKET PRICES IS SUPPORTED BY THE RELATIVELY FLAT "IMPLIED HEAT RATE" IN SWEPCO'S BENEFITS ANALYSIS. HE CONTENDS THAT THE IMPLIED HEAT RATE WOULD DECREASE WITH GREATER PENETRATION OF RENEWABLE RESOURCES. IS THAT A REASONABLE ASSUMPTION?

A. No. As I explained previously, I believe that SPP's assumptions for the future influx of renewable generation in the SPP PROMOD Reference Case, as employed by SWEPCO are reasonable. I also explained above that the market prices (LMPs) employed in the

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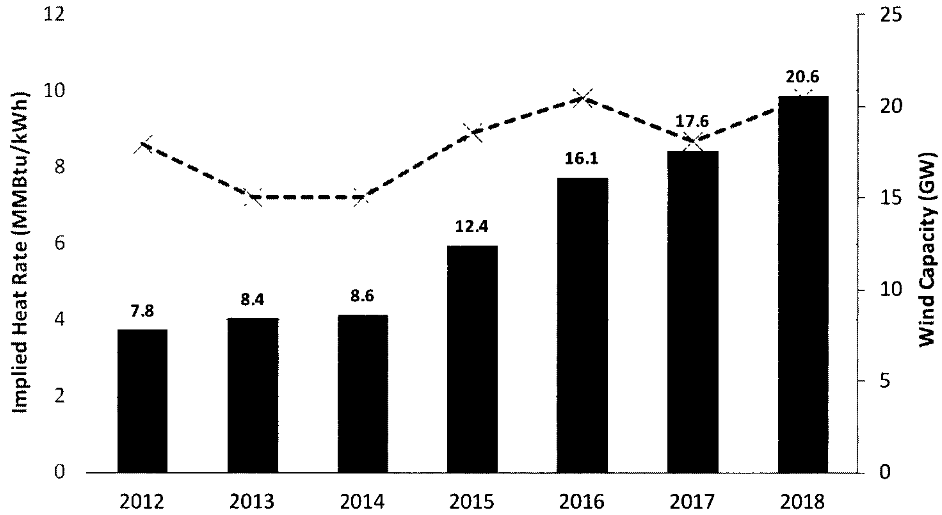
10 Under the "Base Case", simple average LMPs are $34.32/MWh for SPP Central and $38.75/MWh for AEP load zone, resulting in a price differential—as a percentage of the SPP Central LMP—of 12.9% (i.e., ($38.75 - $34.32)/$38.75 = 12.9%).

Company's benefits analyses are not overstated due any supposed understatement of future renewable generation in the SPP footprint. With regard to the implied market heat rate, adding renewables will not necessarily decrease market heat rates due to a number of offsetting factors. In fact, Mr. Pollock's assumption that increased renewable generation will reduce market heat rates is refuted by SPP's own experience to date. As shown with the dark blue bars of Figure 5 below, installed wind generation has increased from approximately 7,800 MW in 2012 to 20,600 MW in 2020. Over that same period, the implied market heat rate (as reported in SPP's own State of the Market reports) has shifted slightly from a range of 7-9 MMBtu/kWh in 2012-2015 to a range of 8.5-10 MMBtu/kWh during 2016-2020. In other words, despite the addition of over 12,000 MW of renewable generation (and including all technological progress over the last decade), SPP's implied market heat rates have *increased.* Importantly, these recent historical SPP market heat rates are higher than those projected in the Company's customer benefits analysis for both the Base Gas and Low Gas (No Carbon) scenarios, through 2031. Between 2031 and 2041 for Base Gas (and 2031 and 2043 for Low Gas), the implied heat rates range between 8.5 and 9.2 MMBtu/kWh, until declining below the 8.5 MMBtu/kWh level in 2042 (2044 for Low Gas). In short, the implied heat rates in the Company's models are already lower than SPP's historical experience with increasing wind penetration, and Mr. Pollock's assertion that they should decline even more is not reasonable.

Figure 5: SPP Market Heat Rates and Installed Wind Capacity (2012-2018)



Source: Values from 2012-2018 SPP State of the Market reports, with implied heat rates inferred from "Implied heat rate" figures.

Q. MR. POLLOCK HAS SUGGESTED SEVERAL REASONS WHY FUTURE SPP MARKET PRICES MAY BE LOWER THAN THE COMPANY'S PROJECTIONS OF THESE PRICES. THESE REASONS INCLUDE LOWER GAS PRICES, IN ADDITION TO THE FACTORS YOU HAVE DISCUSSED ABOVE. ARE THERE ANY REASONS WHY SPP MARKET PRICES MAY BE HIGHER THAN WHAT MR. POLLOCK SUGGESTS IN HIS TESTIMONY?

A. Yes, absolutely. Mr. Pollock fails to address a number of reasons why market prices would be higher than the low prices he projects, particularly if one were to assume future natural gas prices would be below even the Company's low gas price case, as Mr. Pollock suggests. First, renewable generation additions would slow down relative to current projections if future natural gas prices and associated wholesale power prices were to be as low as Mr. Pollock suggests. Thus, Mr. Pollock's assumption that extremely low gas prices—well below the low case projected by the Company and in other long-term forecasts—will prevail for the next 30 years is inconsistent with his assumption that a lot more renewable power projects will get developed than those projected in the SPP PROMOD reference case by SPP and its stakeholders. Second, at Mr. Pollock's very low projected natural gas prices, a lot more SPP coal generation would be retired than currently projected. Third, Mr. Pollock ignores that SPP's low current wholesale power prices are caused in part by a significant surplus of generation in the SPP footprint. As this surplus is reduced and eliminated over time, SPP market prices will adjust accordingly. All three of these factors would increase wholesale power prices in SPP relative to those assumed in Mr. Pollock's testimony—which would increase the net customer benefit of the Company's Selected Wind Facilities.

III. UNDERSTATED CONGESTION COSTS

Q. IN SECTION III. D OF HIS DIRECT TESTIMONY, WITNESS GRIFFEY STATES THAT SWEPCO HAS UNDERSTATED CONGESTION COSTS BY HOLDING THESE COSTS AT THE 2029 LEVEL FOR THE 2030-51 PERIOD. DO YOU AGREE?

A. No. Continuing the 2024 to 2029 level of increases in simulated congestion costs would be unreasonable and inconsistent with industry trends and the Company's ability to mitigate such congestion cost increases. Even growing congestion costs with inflation, let alone at the rate of projected increase in power prices as suggested by Mr. Griffey, would inflate congestion to the point that it would be economical for the Company to mitigate these cost increases. For instance, under the Base Case with No Carbon, growing congestion costs with inflation from 2030 to 2051 would result in a 2027-2051 NPV of congestion costs that exceeds the equivalent NPV of the revenue requirements of constructing a gen-tie between the Selected Wind Facilities and the Tulsa region of the AEP load zone. Assuming the gen-tie serves as a proxy for cost-effective transmission, absorbing the cost of inflated congestion would be unreasonable when either AEP or SPP can cost effectively mitigate these costs. Further, with the expiration of wind production tax credits (PTCs), the current wind generator practice of negative bidding, which has led to negative LMPs at wind generation locations to take advantage of the PTCs, would give way to more traditional bidding behavior that is based on wind generators' short run marginal costs of $0/MWh. To the extent there is curtailment of wind generation outputs at or in the vicinity of the Selected Facilities, this change in bidding practice in the future would also contribute to reducing future wind-related congestion costs.

Q. MR. GRIFFEY CLAIMS THAT "IT IS INCONSISTENT TO ASSERT THAT COST-EFFECTIVE NEW TECHNOLOGY WILL MITIGATE THE COST OF CONGESTION, BUT SOMEHOW THE SAME COST-EFFECTIVE NEW TECHNOLOGY WILL NOT LIMIT THE ENERGY PRICE INCREASES THAT SWEPCO PROJECTS." HOW DO YOU RESPOND?

A. The price levels in competitive wholesale power markets are driven by different factors than the levels of congestion on the transmission system. With current historically low levels of natural gas prices and significant surplus generating capacity in the SPP footprint, it is very likely that wholesale power prices will increase from current levels, as reflected in the Company's fundamental forecasts. While there will be progress in generating technology, I expect that to have less impact on wholesale power prices, considering that the competitive nature of the wholesale markets has already stimulated substantial innovation over the last two decades. The fact that market heat rates have been trending up in the SPP footprint, as